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Production and Processing of U.S. Tar Sands: An Environmental Assessment

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December 1976

PRODUCTION AND PROCESSING OF U.S. TAR SANDS: An Environmental Assessment

Interagency
Energy-Environment
Research and Development
Program Report

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Tar sands is a potential source of synthetic fuel for the U. S. If, when, to what extent and at what rate U. S. tar sands are developed in the future is dependent to a large extent upon the environmental impact of the producing and processing of tar sands. Reported here are the results of a preliminary study to assess the potential primary environmental impacts of production and processing of U. S. tar sands bitumen. Currently there are two basic ways for producing tar sands--mining and in-situ. Producing tar sands by mining methods would be similar to those of mining coal. Solid waste in the form of spent sand would have to be dealt with, but existing technology can control it if good environmental practices are followed. Currently there is no in-situ production technology but it is believed that environmental impacts would be similar to those of conventional oil field production. Facilities used to upgrade tar sand oil would pose environmental impacts same as coking and hydrotreating processes in an oil refinery. Environmentally, in-situ production of tar sands would be preferred. From the viewpoint of resource utilization, production by surface mining methods where economically and technically possible would be preferred. Technical and ecomomic factors will determine if in-situ methods are an alternative to surface mining in environmentally sensitive areas.

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PRODUCTION AND PROCESSING OF U.S. TAR SANDS
AN ENVIRONMENTAL ASSESSMENT

by

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FOREWORD

When energy and material resources are extracted, processed, converted, and used, the related pollutional impacts on our environment and even on our health often require that new and increasingly more efficient pollution control methods be used. The Industrial Environmental Research Laboratory - Cincinnati (IERL-Ci) assists in developing and demonstrating new and improved methodologies that will meet these needs both efficiently and economically.

Factors traceable to the increasing shortfall in U. S. production of natural crude have rekindled interests in U. S. tar sands as a source of synthetic fuel. If U. S. tar sands do become a viable resource base for syncrude, then their commercial development would create activities and sources with potential for environmental impacts. Reported here are the results of a preliminary study to assess the potential primary environmental impacts of production and processing of U. S. tar sands bitumen. This research will be especially applicable to research agencies and the various control agencies associated with energy production. For further information contact the Extraction Technology Branch of the Resource Extraction and Handling Division.

David G. Stephan
Director
Industrial Environmental Research Laboratory
Cincinnati

ABSTRACT

Factors traceable to the increasing shortfall in U.S. production of natural crude have rekindled interests in U.S. tar sands as a source of synthetic fuel. If U.S. tar sands do become a viable resource base for syncrude, then their commercial development would create activities and sources with potential for environmental impacts. Reported here are the results of a preliminary study to assess the potential primary environmental impacts of production and processing of U.S. tar sands bitumen.

With the possible exception attributable to chemical differences between tar sand bitumen and coal, potential environmental impacts of producing tar sands by mining methods would be similar in type to those of mining coal by the same method and in the same area as the tar sand deposit.

Processes for extracting bitumen from the mined tar sand would generate solid waste in the form of spent sand. Constituents and quantities of emissions to air and water are process dependent but existing control technology and good environmental practices are technically applicable.

A viable in situ production technology for producing tar sand reservoirs has not yet been demonstrated. On the basis of methods tested to date, potential environmental impacts of producing tar sands by in situ methods would be very similar to those of conventional oil field production.

Facilities used to upgrade tar sand oil would pose potential primary impacts of the same type as coking and hydrotreating processes in an oil refinery. Whether or not new upgrading facilities would have to be constructed or existing facilities might be used would depend on location and size of tar sand deposit.

Environmentally, in situ production of tar sands would be preferred. From the viewpoint of resource utilization, production by surface mining methods, where economically and technically possible, would be preferred. Technical and economic factors will determine if in situ methods, or possibly underground methods, are an alternative to surface mining in environmentally sensitive areas.

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SECTION I

INTRODUCTION

Reported are the results of a preliminary study to determine the potential primary environmental impact of producing and processing bitumen in U.S. tar sands deposits. Bitumen in the U.S. deposits, currently estimated at 25 to 30 billion barrels, is a potential source of synthetic crude oil. Laboratory research and experimental or pilot field projects on methods of recovering tar sand bitumen have been conducted on an intermittent basis for some 3 decades in the U.S. Commercial interests in the deposits have waxed and waned over the years. Up to the present time, the U.S. tar sands have not been able to compete with other energy resources for the capital required for their commercialization as a source of syncrude.

The United States' increasing dependence on imported natural crude has been well publicized. National policies and programs to decrease this dependence have caused an upsurge in interest in the contribution that U.S. tar sands, as well as other potential syncrude resources, could make to the U.S. energy picture.

At the present time, the only tar sand deposit being commercially produced on a large scale is the vast Athabasca deposit in Alberta, Canada, an operation that began about 10 years ago. However, inplace reserves of this deposit are about 20 times greater than those of all U.S. deposits as they are now known.

Many interacting factors will determine if, when, to what extent, and at what rate U.S. tar sands are developed in the future. One of these factors, the potential primary environmental impact of the producing and processing the tar sands, is the subject of this report.

Results of the study are presented in five sections. In order of presentation, the contents of these sections relate to:

(1) Characteristics of U.S. tar sands deposits, i.e., their geographical distribution and properties

(2) Probable emission sources and other potential causes of primary environmental impact expected to be associated with methods of producing tar sand reservoirs and with extraction and upgrading of tar sand bitumen

(3) Assessment of potential primary environmental impacts of the production and processing segments of a U.S. tar sands industry

(4) Environmentally preferred components of a tar sand operation

(5) Perspective of U.S. tar sands as a source of syncrude.

SECTION II

CHARACTERISTICS OF U.S. TAR SANDS

Tar sands is a general term applied to deposits of unconsolidated and consolidated clastic sediments whose interstitial spaces are partially or completely saturated with highly viscous bitumen or hydrocarbon materials. Bitumen also occurs in fractures and vugular pores of carbonate rocks but generally not in sufficient quantities to make them of commercial interest as a source of syncrude. Other terms used to refer to or include tar sands are bituminous sands, asphaltic rocks, and oil-impregnated rocks.

Although there is no clearcut definition of tar sand reservoirs, they differ from conventional oil reservoirs by the high inplace viscosity of the oil or bitumen. A general rule of thumb is that at reservoir temperatures heavy oil will flow to the well bore at very low rates; whereas, for practical purposes, bitumen in tar sands will not flow at all. Order of magnitude values of the viscosity of the bitumen can range from several hundred thousand to several million centiposes.

GEOGRAPHIC DISTRIBUTION OF U.S. TAR SANDS

More than 500 occurrences of surface and shallow oil-impregnated rocks, including tar sands, are known in 22 states (see Figure 1)(1-3), but their evaluation as a resource base is not complete. Major U.S. tar sands, as shown in Tables 1 and 2, have been estimated to represent a resource base or inplace reserves of between 18.7 and 30.1 billion barrels.*

The State of Utah, with some 85 to 95 percent of inventoried U.S. tar sand resources, has been comparatively active in evaluating its bitumen-bearing rocks. Even in the case of Utah, "reserve estimates assigned to deposits are largely a matter of personal judgment and educated guesswork buttressed with a certain amount of carefully considered data".(4)

Other states are beginning or attempting to begin work to inventory their deposits in greater detail than they are now known. Alabama has recently completed a study(5) of the bitumen-bearing Hartselle Sandstone in northern Alabama. Missouri, Kansas, and Oklahoma are initiating or hope to initiate cooperative efforts in the heavy-oil region of their tristate area, parts of which also contain tar sands.(6-10) Oklahoma is investigating best

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* One barrel equals 42 gallons; one gallon equals 3.76 liters.

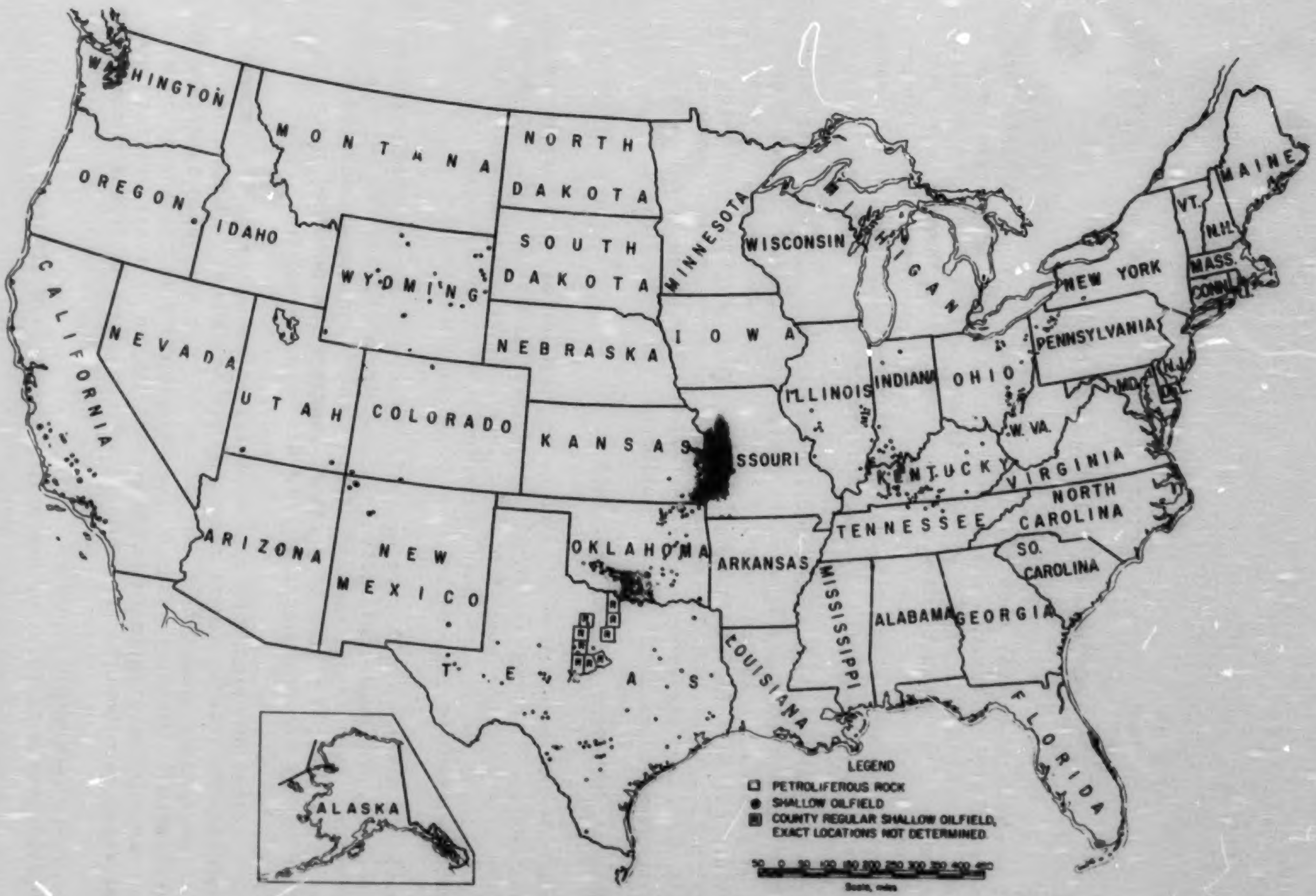
WASHINGTON
OREGON
CALIFORNIA
IDAHO
NEVADA
MONTANA
WYOMING
UTAH
ARIZONA
COLORADO
NEW MEXICO
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
MINNESOTA
IOWA
MISSOURI
ARKANSAS
LOUISIANA
WISCONSIN
ILLINOIS
MICHIGAN
INDIANA
OHIO
KENTUCKY
TENNESSEE
MISSISSIPPI
ALABAMA
GEORGIA
FLORIDA
SO. CAROLINA
NORTH CAROLINA
VIRGINIA
W. VA.
PENNSYLVANIA
NEW YORK
MD.
N.J.
VT.
N.H.
MAINE
MASS.
CONN.
ALASKA
LEGEND
☐ PETROLIFEROUS ROCK
● SHALLOW OILFIELD
▣ COUNTY REGULAR SHALLOW OILFIELD, EXACT LOCATIONS NOT DETERMINED
50 0 50 100 150 200 250 300 350 400 450
Scale, miles

FIGURE 1. OCCURRENCE OF PETROLEUM-IMPREGNATED ROCKS AND SHALLOW OILFIELDS IN THE UNITED STATES

[From Reference (1)]

TABLE 1. DEPOSITS OF BITUMEN-BEARING ROCKS IN THE UNITED STATES WITH RESOURCES OVER 1,000,000 BARRELS[1]

State and name of deposit	Resources (millions of barrels)	
California:		
Edna	141.4–	166.4
South Casmalia	46.4	
North Casmalia	40.0	
Sisquoc	26.0–	50.0
Santa Cruz	10.0	
McKittrick	4.8–	9.6
Point Arena	1.2	
Kentucky:		
Kyrock area	18.4	
Davis-Dismal area	7.5–	11.3
Bee Spring area	7.6	
New Mexico: Santa Rosa	57.2	
Texas: Uvalde	124.1–	140.7
Utah:		
Tar Sand Triangle	10,000.1–	18,100.0
P.R. Springs	3,700.0–	4,000.0
Sunnyside	2,000.0–	3,000.0
Circle Cliffs	1,000.0–	1,300.0
Asphalt Ridge	1,000.0–	1,200.0
Whiterocks	65.0–	125.0
Hill Creek	300.0–	400.0
Lake Fork	15.0–	20.0
Raven Ridge	100.0–	125.0
Rimrock	30.0–	35.0
U.S. total	18,694.9–	28,853.2

[1] Source: Extraction of energy fuels. Federal Council for Science and Technology. Bureau of Mines open file report 30-73. Washington, D.C. 1972.

Reproduced from Reference (3)

TABLE 2. U.S. TAR SANDS RESERVES[1]

State	Largest published estimate (in place) billion barrels	Date of latest new information
Alabama	0.15 *	1973
California	.321	1963
Kansas	.05	1964
Kentucky	.084	1951
Missouri	.0009	1935
New Mexico	.057	1942
Ohio	.0005	1941
Texas	.14	1962
Utah	29.3	1973
Total	30.1	

[1] Compiled by Dr. Frederick Camp of Sun Oil Co. All data represents the work of other investigators. There is no input of original data from the Sun Oil Co.

Notice: Only Utah has reserves reported greater than 1,000,000,000 bbls. Only Utah and Alabama report recent exploration.

Reproduced from Reference (3).

* 1975 estimate for the Hartselle deposit is 1.18 billion barrels (5).

use of tar or asphaltic sands in southern Oklahoma and Kentucky is compiling existing information preparatory to publishing on that state's tar sand deposits.(6)

Utah has 51 deposits(11) ranging in size from those with little to no interest as a resource to the Tar Sands Triangle group of deposits (see Figure 2) with inplace resources estimated at 12.5 to 18 billion barrels.(3,4,12,13) Of Utah's inventoried 24 to 28 billion barrels of inplace bitumen, some 40 percent occurs in central Utah in the Uinta Basin (see Table 3) and 60 percent in central southeast Utah.

PROPERTIES OF U.S. TAR SANDS

Utah's major deposits occur in sandstone and siltstone.(12) Ritzma(11) summarizes the lithology of Utah's deposits as follows:

> "Most deposits, particularly those of major size, occur in sandstone which, with finer grain size, grades into siltstone and, with coarser grain size, grades into grit and conglomerate. More than 98 percent of the estimated oil in place in Utah's deposits is contained in sandstone and siltstone.
>
> Along the south flank of the Uinta Basin, the Argyle Canyon, Minnie Maude Creek and Willow Creek deposits contain notable amounts of oil-impregnated limestone in the Green River Formation. The Thistle deposit, also in the Green River, contains considerable heavily impregnated oolitic limestone and coquina. The Split Mountain deposit occurs in coarse crystalline and vuggy Park City Formation limestones. The Daniels Canyon deposit occurs in highly fractured quartzite and siliceous limestone.
>
> In central southeast Utah, all deposits are contained in sandstone, siltstone, and some conglomerate, except for small amounts of oil-impregnated limestone found in San Rafael Swell and Teasdale deposits and localities.
>
> The Mexican Hat deposit (San Juan County) occurs in Pennsylvania carbonate rocks, and the Rozel deposit (Box Elder County) is found in oolitic mud and salt on the shores of Great Sale Lake".

Values of porosity, permeability, and oil and water saturation exhibit variations and ranges that might be expected in tar sand deposits. Values of these and other properties of major Utah tar sand deposits are shown in Table 4.(12,14)

In the winter of 1975, the Laramie Energy Research Center conducted a reverse combustion experiment near Vernal, Utah, in the northwest Asphalt Ridge deposit.(15) Average characteristics of 22 samples from cores of that Rim Rock Member (Mesa Verde Formation) test are as follows.(14)

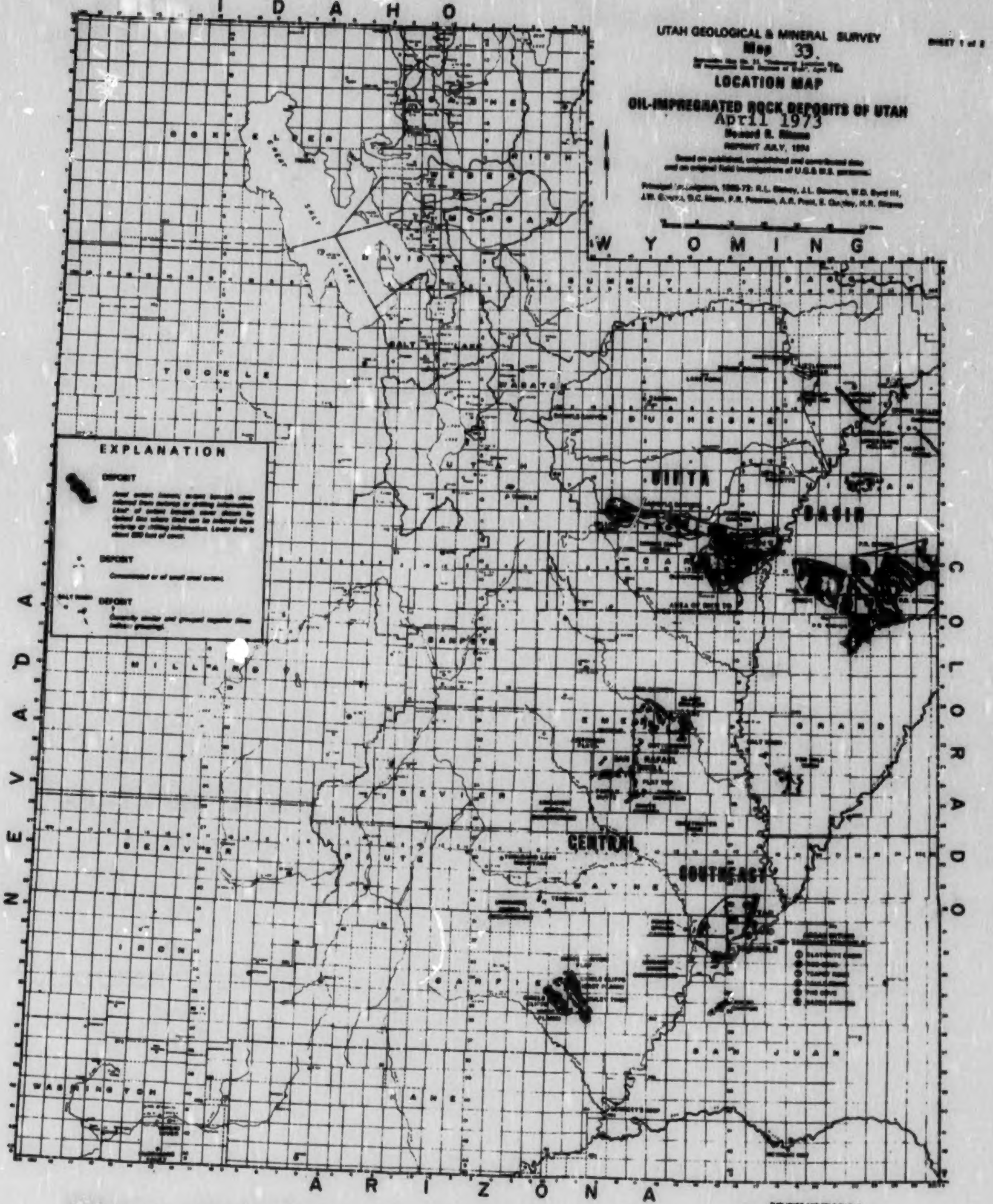
IDAHO
UTAH GEOLOGICAL & MINERAL SURVEY
Map 33
LOCATION MAP
OIL-IMPREGNATED ROCK DEPOSITS OF UTAH
April 1973
REPRINT JULY, 1974
WYOMING
EXPLANATION
DEPOSIT
DEPOSIT
DEPOSIT
TOOELE
MILLARD
BEAVER
IRON
WASHINGTON
SEVIER
SANPETE
EMERY
GRAND
SAN JUAN
WAYNE
GARFIELD
KANE
PIUTE
SALT LAKE
DAVIS
MORGAN
WEBER
SUMMIT
WASATCH
UTAH
DUCHESNE
UINTA
BASIN
CENTRAL
SOUTHEAST
COLORADO
NEVADA
ARIZONA

FIGURE 2. DISTRIBUTION OF TAR SAND DEPOSITS IN UTAH
[From Reference (11)]

TABLE 3. MAJOR TAR SAND DEPOSITS IN UTAH

[From References (4) and (12)]

Deposit	Bitumen In-place (10^6 bbls)
Uinta Basin	
P. R. Spring	4,000 - 4,500
Sunnyside	3,500 - 4,000
Hill Creek	1,160
Asphalt Ridge	1,150
Argyle Canyon	100 - 125
Raven Ridge	125 - 150
Whiterocks	65 - 125
Central Southeast Utah	
Tar Sands Triangle	12,500 - 16,000
Circle Cliffs-East Flank	860
Black Dragon	100 - 125
Family Buttes	100 - 125
Circle Cliffs-West Flank	450

TABLE 4. CHARACTERISTICS OF UTAH'S MAJOR TAR SANDS

	Average Values (14)					Ranges, [] = No. of Samples, () = Average Value (12)					
Deposit	Porosity % P. V. (b)	Permeability, md	Bitumen sat., % P. V.	Water sat., % P.V.	Compressive strength, psi	Areal Extent (sq. miles)	No. of pay zones	Gross thickness of pay (Stratigraphic range, feet)	Overburden Thickness (feet)	Gravity ° API	Gallons/ Ton
Asphalt Ridge	19.6	497	51.4	2.7	2,491	20-25	2-5	10-135	0-500+	8.6-17.5 [4]	13-27 [6]
N.W. Asphalt Ridge	22.8	603	45.2	20.2	1,598						6-26 [4]
Circle Cliffs	12.3	228	17.7	—	—	27.7	1-3	5-310	0-500+	-11.1-22.4 [9]	—
Hill Creek	20.2	325	29.7	2.1	6,555	115-125	6-13 [3]	53-65 (61)	0-500+	5.5-10.5 [5] (7.9)	1.0-21.2 [129]
P. R. Spring	25.0	1,510	42.5	3.0	4,784	240-270	1-13 [13] (7)	10-102 (39)	0-500+	5.8-10.3 [37][9.5]	0.2-30.5 [454]
Sunnyside	21.3	729	44.8	—	7,805	35-90	1-12	15-550	0-500+	6.2-6.7 [2]	—
Tar Sand Triangle	20.0$^{(c)}$ 19.7	207$^{(c)}$ 788	6.3$^{(c,d)}$ 70.7	— —	3,242$^{(c)}$ —	200-230	1	5-300	0-1600+	-3.6-9.6 [5] (+4.5)	4.9-13.7 [5](9.3)
White Rocks						0.6-0.75	1	1000+	0-470	4.4-12	4.5-31.4

(a) All reference (14) values based on samples from cores except as indicated.
(b) P. V. = pore volume.
(c) Surface samples.
(d) Total liquid saturation. percent by weight.

	Bitumen Inplace	After Bitumen Extracted
Porosity, percent	10.5	28.5
Permeability, millidarcy	182	615
Oil saturation:		
percent of pore volume	54.0	--
percent by weight	7.6	--
Water saturation, percent of pore volume	16.0	--

Listed below are ranges in average properties of the Hartselle Sandstone deposit at various locations in northwest Alabama.(5)

	Range	Average
Porosity, percent pore volume	6.0 - 23.8	--
Oil saturation, percent pore volume	8.4 - 48.9	--
Thickness, feet	2 - 55	--
Barrels per acre-foot	60 - 499	259
Barrels per acre	232 - 12,802	5,270
Gallons per ton	0.8 - 7.0	3.7

Depths to the Hartselle Sandstone range from zero to more than 1,000 feet. Oil inplace is estimated at 1.18 billion barrels over 350 square miles where the formation is thicker than 150 feet.

Analysis of oils extracted from the tar sands vary from deposit to deposit.(4,5,11,16,17) Sulfur in the Uinta Basin oils (approximately 80 samples) is on the average about an order of magnitude less than in the oils from central southeast Utah (approximately 30 samples). For the former, Ritzma(4) has cited values ranging from 0.14 to 0.87 percent with an average of 0.4 percent. In contrast, sulfur in oils from central southeast Utah range from 1.64 to 6.27 percent with an average of 4.0 percent. Ranges for sulfur and nitrogen in extracts from the Hartselle bitumen in Alabama are 1.08 to 1.43 percent and 0.29 to 0.5 percent, respectively.(5)

Average concentrations of metals in 220 tar ash samples from Unita and Grand Counties, Utah deposits are listed below in parts per million.(17)

Chromium	102.92	Manganese	547.47
Cobalt	103.10	Nickel	203.00
Copper	109.63	Zinc	211.63

Other metals in the tar ash identified by emission spectroscopy are aluminum, calcium, iron, lead, magnesium, silicon, silver, sodium, titanium, and vanadium.

Citing Humphreys*, McConville(18) compared raw bitumen and synthetic crude product from the Great Canadian Oil Sands, Ltd. commercial operation at the Athabasca deposits:

	Raw Bitumen	Synthetic Crude Product
Sulfur	4.5 - 5.0%	0.2%
Nitrogen	0.5 - 1.0%	0.1%
Vanadium	150 ppm	Nil
Ash	1.0%	Nil

Other values noted for metals in the Athabasca bitumen (in ppm) are:(19)

Vanadium	210; 250; 290
Nickel	82; 100
Iron	75
Copper	2; 5

GENERAL ENVIRONMENTAL SETTING OF UTAH'S MAJOR TAR SAND DEPOSITS

Utah's major deposits are characteristically in relatively inaccessible and sparsely populated areas and often rugged mountainous terrain with Asphalt Ridge being the more notable exception. The Sunnyside deposit is at elevations of 8,000 to 10,000 feet with elevations of other deposits ranging from 6,000 to 8,700 feet. Canyons with 800 to 1,000-foot relief are commonplace. The more prominent streams are the Colorado and Green Rivers but intermittent streams and dry valleys are the general rule in the immediate environs of the tar sands.

Deposits underlie Federal, state, private, and Indian lands, but most of the land is Federally-owned.(13)

Ritzma(11) summarized the setting of Utah's deposits as follows:

> "Lack of or difficult access to large sources of fresh water will hamper exploitation of these deposits as sources of oil in most areas. Water supplies may be available in parts of the Uinta Basin to support mining and processing operations on rich, concentrated deposits, such as Whiterocks and parts of Asphalt Ridge. Water supply is a serious factor in considering exploitation of the large potential reserves of the Tar Sand Triangle and Circle Cliffs.
>
> The Circle Cliffs deposits are partially within the extended boundaries of Capitol Reef National Park and the remainder of the deposits is within areas proposed for various scenic, recreation, and wilderness preserves. Access to the deposits is severely limited.

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* Humphreys, R. D., "Some Engineering Aspects of the Tar Sands Project", Paper presented at the 75th Annual General Meeting of CIM, Vancouver, B. C., April, 1973.

The Tar Sand Triangle deposits lie mostly within the Glen Canyon National Recreation Area and immediately west of Canyonlands National Park. Access to the area for development purposes is severely restricted.

Other conflicts over land use and environmental considerations are expected to greatly influence development of all of Utah's deposits, particularly those susceptible to open-cut mining methods."

SECTION III

PRODUCTION OF TAR SANDS

PRODUCTION METHODS

Laboratory research, field experiments, and pilot field projects have involved two basic approaches for producing tar sand reservoirs--mining of tar sand as an ore for subsequent extraction and upgrading of the bitumen values and in situ methods of reducing viscosity of the tar sand bitumen so that it will flow to a producing well.

Mining

When the ratio of waste (e.g., overburden) to tar sand is below certain limits, tar sand reservoirs can be produced by surface mining technology quite similar to that used for surface mining of coal and ores. A break-even value for the overburden to pay ratio is difficult to determine initially(18) and requires analysis of several costs including those of alternative mining methods and equipment, transportation of ore to a surface processing facility, the processing facility, transportation and disposal of spent sand, and environmental protection measures. The characteristics of the waste material to be stripped, i.e., whether or not the overburden and any nonproductive strata within the tar sand deposit require drilling and blasting, also affects the costs of a surface mining operation. Richness of the tar sand ore has obvious importance to determination of the break-even ratio of waste to tar sand as does the market value of syncrude. In his discussion of commercialization of the Athabasca deposits, McConville(18) states that, with current technology and costs, probable limiting ratios of 1:1 to 1:1.5 for large tar sand bodies although for small areas the limiting ratios may be as high as 2.5:1 to 3:1, depending on richness of the deposit.

Discussion in U.S. literature is almost exclusively concerned with surface mining as opposed to underground mining. In areas where overburden would be too thick for an economical surface operation, underground mining versus in situ methods would require an analysis of tradeoffs between the two methods. Although about 90 percent of the bitumen can be recovered from the tar sand mined by underground methods, some percentage of the tar sand would not be mined. Maximum bitumen expected to be recoverable by in situ production is around 50 percent. The tradeoff analysis would then center around what percentage of the tar sand ore would have to remain inplace for an underground operation. Also, if one of the constraints facing an underground operation is to prevent or substantially reduce the potential for surface subsidence over a mined-out area, then this percentage could be quite significant and this, in effect, might completely offset the higher recovery efficiencies from mined ore. During this study, no in-depth information was noted on whether or not underground mining of U.S. major tar sand deposits is practical from a mining engineering point of view.

In Situ Production

The approach of in situ methods for producing a tar sand reservoir is that of reducing viscosity of bitumen so that vapors or oils will move to producing wells where it can be lifted to the surface. Although field projects to test various in situ approaches have been conducted in the U.S. and Canada, a commercial operation for producing tar sands by in situ methods is still in the future.

Two advantages of in situ over surface mining methods are that the former would eliminate the need for handling and processing vast tonnages of bitumen-bearing materials and for disposing of the resultant spent sand waste. One disadvantage, from a resource utilization point of view, is that recovery efficiency would probably be no greater than about 50 percent compared to around 90 percent probable from processing of mined tar sand. The heterogeneous and nonuniform nature of tar sand characteristics also poses problems in prediction and control of in situ performances and processes.

As indicated previously, a principal factor involved in deciding between in situ and surface mining methods is the ratio of thickness of overburden and nonproductive layers in a deposit to the thickness of the pay sand or sands. Although this ratio may be uneconomical for a mining operation, the properties (e.g., fractures and joints) of the overburden or perhaps its thickness could be insufficient to confine the pressures associated with some in situ methods. Thus, at least in concept, there could be some tar sands at depths intermediate between those favorable for surface mining and those for in situ methods that involve a build-up of pressure in the reservoir. Which of the in situ methods that may ultimately be applied for commercialization of U.S. tar sands is not known within the current state of knowledge. About the most accurate statement that can be made at this time is that no single method will be applicable to all deposits.

The U.S.S.R. is reported to have developed a combination of underground mining and in situ methods to produce high viscosity crude. In commercial use since 1972, the thermal-mining technology involves sinking of mine shafts to a depth above the pay zone, drilling and blasting of passages to drilling/production galleries, and drilling of inclined and/or horizontal production wells from the galleries. Stream is injected into the reservoir, produced oil and water are moved to a sump, and oil is separated from the water and pumped to a central collecting point where it is heated again before it is pumped to the surface. Production to date is from depths to 650 feet with 50 to 60 percent recovery from a reservoir containing crude with viscosities of 15,000 to 20,000 centipoises.(20)

SURFACE MINING

The basic technology of area and contour methods for surface mining of coal are expected to be applicable to U.S. tar sand deposits in the event of their commercialization. The area method (Figure 3) would apply to deposits underlying flat terrain and the contour method (Figure 4) and its variations (see Appendix for illustrations) to hilly or mountainous terrain. A considerable body of literature exists on these methods of mining coal with a central theme of much of the more recent literature concerned with variations and practices to reduce impacts of mining. The methods are aptly described in summary form in References (21) and (22).

Adaptation of the longwall method for mining deep underground coal to mining of shallow coal deposits is under investigation.(23,24) Should this adaptation of the method, called longwall stripping(23), prove to be commercially practical, it too might be a candidate for mining some tar sands deposits from the surface (see Figure A-7 in Appendix A).

Materials Handling

Surface mining of U.S. tar sands would involve removal and handling of substantial tonnages of material including overburden, ore, and any interbedded waste rock. In that sense, a surface tar sand mine operation would be essentially analogous to a surface coal mine. However, once the mined tar sand is processed (bitumen extracted), large quantities of spent sand will also have to be handled. In this sense, the materials handling requirements associated with a tar sands mining operation would be different from those of a surface coal mine operation. If an extraction plant is located near the tar sands mine, which would be the expected case in a large operation, the spent sand presumably would be returned to the mine area for disposal.

A perspective of the material that would be handled can be gained by assuming a U.S. mining operation that supplies tar sand feed to an adjacent extraction plant supplying an upgrading plant produing 10,000 barrels* per day of syncrude. Then, using a tar sand feed containing 20 gallons of bitumen per ton of sand (approximately mid-range of values in Table 4), approximately 29,000 tons of tar sand ore per day would be required if the ore contained no appreciable water. After extraction of the bitumen, about 26,000 tons per day of spent sand would need to be returned to the mine or some other area for ultimate disposal.** If an overburden to pay ratio of 1:1 is assumed, then an additional 29,000 tons of this material would have to be handled, giving a total materials handling requirement of 84,000 tons per day. Multiple handling of some portion of the material would be required as mining and reclamation operations proceed.

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* Size of plant used in the subsequent section on extraction and upgrading; see Figure 11 in that section.

** In concept, depending on its properties, impurities and distance to a market, the spent sand could become available as a material for construction or other industries using quartz sand as a raw material.

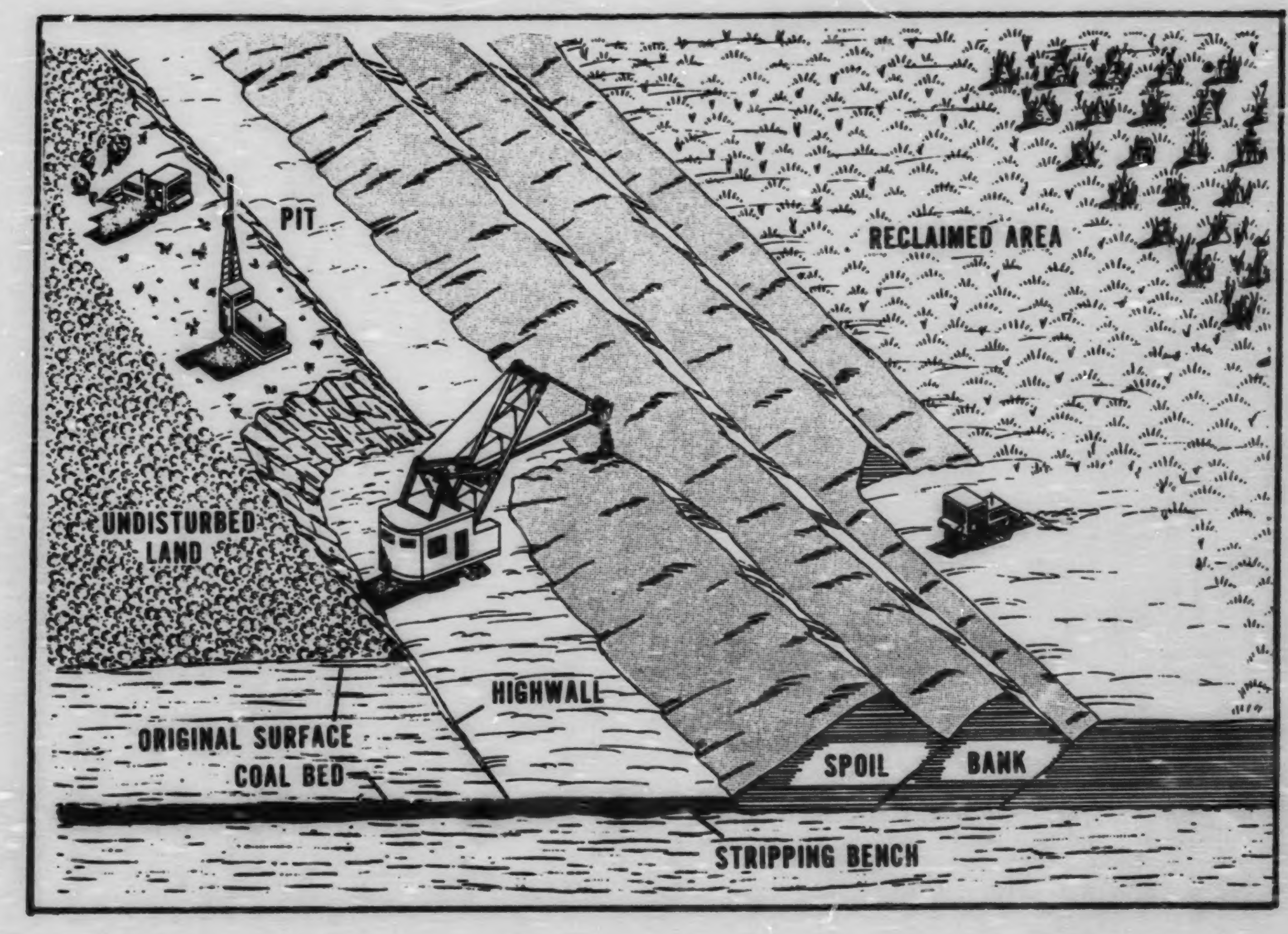

PIT
RECLAIMED AREA
UNDISTURBED LAND
HIGHWALL
ORIGINAL SURFACE
COAL BED
SPOIL
BANK
STRIPPING BENCH

FIGURE 3. AREA STRIP MINING WITH CONCURRENT RECLAMATION
(Reproduced from Reference 21)

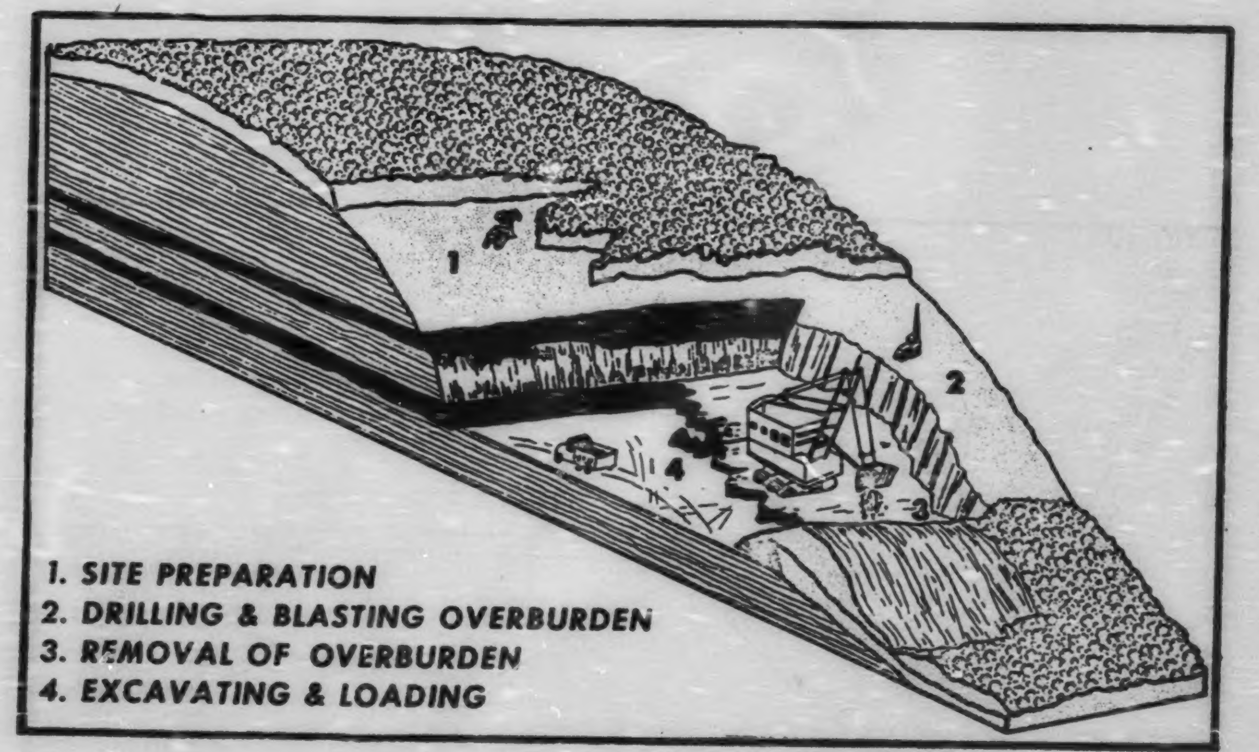
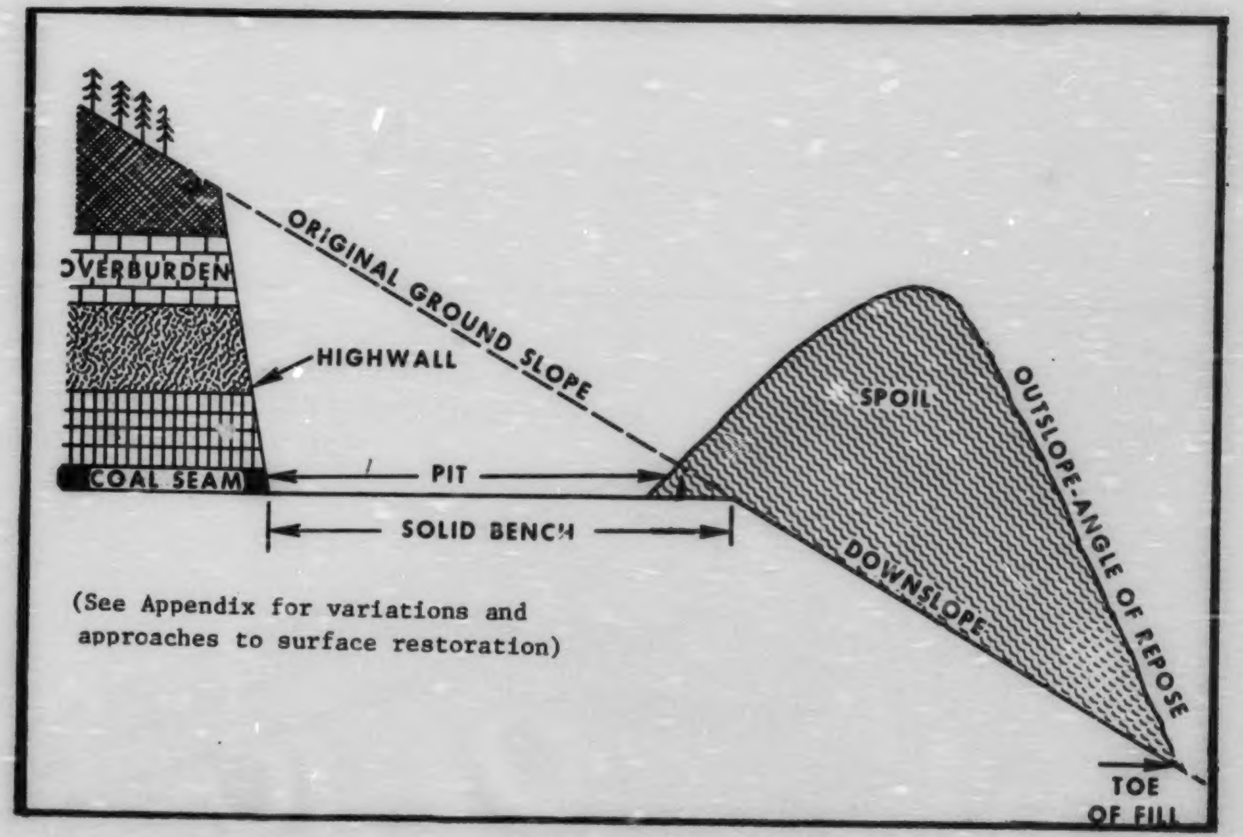

1
2
3
4
1. SITE PREPARATION
2. DRILLING & BLASTING OVERBURDEN
3. REMOVAL OF OVERBURDEN
4. EXCAVATING & LOADING

FIGURE 4. CONTOUR MINING
(Reproduced/Modified from Reference 21)


ORIGINAL GROUND SLOPE
OVERBURDEN
HIGHWALL
COAL SEAM
PIT
SOLID BENCH
SPOIL
DOWNSLOPE
OUTSLOPE-ANGLE OF REPOSE
TOE
OF FILL

(See Appendix for variations and
approaches to surface restoration)

FIGURE 4. (Continued)

The operation of Great Canadian Oil Sands, Ltd. (GCOS) at the Athabasca deposits has proven the technical feasibility of surface mining, at least at that location. That integrated operation can produce 55,000 barrels of oil per calendar day by processing 140,000 tons per day of tar sand mined at a stripping ratio of 0.5:1.(18) Other proposed Canadian mining operations include(18):

Company	Syncrude Production (bpcd)*	Tar Sands Ore (10^6 tpy)**	Overburden or Waste (10^6 tpy)	Stripping or Waste to Pay Ratio
Syncrude Canada	125,000	92	45	0.5:1
Shell Canada and Shell Explorer	100,000	75	29	0.38:1
Petrofina Canada, et al.	122,500	?	?	1.5:1

U.S. tar sand deposits are much smaller than the Athabasca deposit and thus a single U.S. operation the size of any of these Canadian facilities is highly unlikely.

The following materials handling operations would probably be characteristic of a U.S. tar sand surface mine:

- Surface clearing
- Removal of overburden
- Mining of ore (tar sand)
- Removal of barren rock or ore that is too low in grade
- Construction of haul roads
- Transportation of ore to processing facility
- Construction of impoundments and drainage diversion channels
- Transportation of tailings
- Surface grading and contouring for reclamation
- Rehandling of temporarily-stored waste.

As mining progresses and reclamation begins, different combinations of these operations may be going on simultaneously.

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* Barrels per calendar day.

** Tons per year.

The size of an operation, terrain, mining method, rock properties, geology, characteristics of the tar sand, and distance to a process plant would all play a role when choosing type, size, and mix of equipment to be used, e.g., shovels, draglines, bulldozers, ripping dozers, pan scrapers, large trucks, bucket-wheel excavators, conveyors, and pipelines for tailings.

Potential Environmental Impacts

The types of primary environmental impacts that could result from a surface tar sand mining operation are shown in Table 5. Of the types indicated, those that actually occur, as well as their duration and severity, will depend on details of mining and material handling methods employed; size of the operation; all elements of the premining environment; and the degree to which sound environmental protection measures are practical during planning, mining, and surface restoration phases of the operation. Area mining is generally considered to pose less potential for impact than contour mining but some of the major deposits in the U.S., particularly in Utah, are in areas of high relief.

Air Emissions--

Air emissions should be quite similar to those from surface mining of coal except that as tar sands are exposed, volatiles in the bitumen could be an additional emission source. Severity would depend on temperature, elevation, and whether or not fractures in the overburden have allowed some of the volatiles to escape during geological time.

Materials handling operations can produce dust, particularly if overburden or rehandled waste is dry and unconsolidated. Haul roads are a source of dust when transporting ore and spent sand but water or hydroscopic materials can be used to reduce dust generated from this source. Ore could be transported by conveyors which would eliminate dust from hauling of ore to an extraction plant. Spend sand can be slurried with extraction process water and pumped to a temporary or permanent disposal area which would also eliminate the use of haul roads for this purpose.

Diesel engines emit particulates, sulfur oxides, nitrogen oxides, hydrocarbons, aldehydes, and organic acids.(25) Quantities would depend on fuel composition, size and mix of diesel-powered equipment, terrain, size of mining operation, and whether or not ore and/or spent sand is transported in earth-moving equipment.

Water Emissions and Solid Wastes--

Surface mining operations that disturb existing or expose new surfaces would increase availability of solubles and suspendable constituents for aqueous transport. Duration and severity of impacts on water quality resulting from these operations would depend on terrain, climate, details of mining method and environmental protection practices, geochemistry of overburden, method of transporting ore and/or spent sand, surface drainage patterns, and geohydrology.

Excluding possible effects of chemical differences between tar sands and coal, types of impacts on water quality of a surface tar sand mine would

TABLE 5. TYPES OF POTENTIAL PRIMARY ENVIRONMENTAL IMPACTS--SURFACE MINING OF TAR SANDS

	POTENTIAL IMPACT						
	Increased Air Emissions				Increased Availability of Aqueous Transportable Materials		
Operation or Source of Impact	Dust	Engine Exhaust	Volatile Hydrocarbons of Bitumen	Solid Waste Generated	Inorganics	Organics	Suspended/ Dissolved Solids
Site Preparation	X	X					X
Surface Clearing (cleared area)	X	X		X	(X)	(X)	(X)
Stripping (stripped area)	X	X		X	(X)	(X)	(X)
Tar Sand Extracting (mined area)		X			(X)	(X)	(X)
Haul Road Transportation (construction)	X (X)	X (X)					X (X)
Tailings Disposal	X	X		X			
Bitumen in Tailings or Low Grade Tar Sand Waste						X	
Fines in Tailings							X
Stripped Waste				X	X	X	X
Solubles or Water-Transportation Particles in Overburden					X	X	X
New Surface			X			X	
Increases in Surface Slope From Waste Disposal							X
Rehandling of Materials: Backfilling, Grading, and Recontouring	X	X			X	X	X

TABLE 5. (Continued)

Operation or Source of Impact	Increased Landslide Risk	Destruction of Existing Vegetation	Alteration of Habitats	Topographic Changes	Drainage Diversion	Increased Noise	Changes Ground Water Regime: Physical	Changes Ground Water Regime: Chemical
	POTENTIAL IMPACT: Surface Changes							
Site Preparation		X	X	X	X	X		
Surface Clearing (cleared area)		(X)	(X)	(X)	(X)	X		
Stripping (stripped area)		(X)	X	X			(X)	(X)
Tar Sand Extracting (mined area)				(X)		X	(X)	(X)
Haul Road Transportation (construction)		(X)	(X)	(X)	(X)	X (X)		
Tailings Disposal						X		
Bitumen in Tailings or Low Grade Tar Sand Waste		X						(X)
Fines in Tailings								
Stripped Waste								
Solubles or Water-Transportation Particles in Overburden			X				X	X
New Surface								X
Increases in Surface Slope From Waste Disposal	X							
Rehandling of Materials: Backfilling, Grading, and Recontouring						X		

be essentially analagous to those of a surface coal mine in the same area. Surfaces disturbed, exposed, or created by mining operations, are bared to the erosive action of precipitation runoff with attendant increases in suspended solids with the extent being a function of slope and "looseness" of the surface materials. Good mining practices in sloping terrain provide for diversions of runoff upgradient from a mine and/or downgradient retention basins as well as reducing the slope of waste material as mining progresses. Permeable materials underlying bare surfaces are also exposed to the chemical action of water on soluble components. This water can then return to the surface downgradient to become a part of surface water or enter the groundwater, depending on site specifics.

The organic phases of tar sand bitumen are more similar to petroleum than to coal. Hence, exposed tar sand surfaces and unrecovered bitumen in spent processed sand, if exposed to the physical action of runoff, will be a potential nonpoint source of organic loading (primarily alkane--or paraffin--type hydrocarbons of heavy molecules with lesser amounts of aromatics) that is not associated with a surface coal mine operation.

Sulfur in the bitumen is present as organic compounds which are oil soluble and should not be leachable. Also, trace metals in the bitumen, as in petroleum, are present as oil soluble organic compounds, e.g., porphyrins and salts of organic acids. Although a majority of these compounds are insoluble in water, some could hydrolyze and the metal ion become soluble in water. The extent to which hydrolysis will occur is pH and rodox potential dependent, being less pronounced in alkaline solutions (e.g., alkaline surface and ground waters).

A potential for impact on water quality could develop if either (1) hydrolyzable components in the bitumen of tar sand ore wasted at the mine site or in spent sand wastes or (2) their hydrolyzed products become available for aqueous transport. However, surface-breached tar sands have been exposed to surface waters over geologic time and subsurface deposits are a part of the geohydrological regime of an area. Thus, it can be conjectured on one hand, that surface mining could reduce potential for impacts on water quality because tar sand ore would be removed for processing. On the other hand, increased exposure (change from an anaerobic to aerobic environment) of tar sand bitumen as a result of (1) tar sand benches exposed during mining operations, (2) mine-wasting of low-grade tar sands, and (3) presence of unrecovered bitumen on surface areas of spent sand grains would be sources of water quality degradation.

If tar sands in their natural setting (before mining) are now degrading water quality*, then surface mining of tar sands could add to this degradation. If tar sands in their natural setting are not presently degrading water quality, surface mining could still result in conditions that have potential for impacting water quality because of exposure of tar sand bitumen. Evaluation of this potential would require field and laboratory studies.

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* No data were noted on water quality in the environs of a tar sand deposit.

In the event that bitumen in the tar sand is extracted by a hot water process with caustic soda added, some components of the bitumen, including metal compounds and aliphatic and aromatic organic acids, would be expected to react with the water and dissolve (hydrolyze). In that case, unrecovered bitumen in the spent sand should contain very little free water leachable components. Any process water wasted with the spent sand could, however, contain hydrolyzed products.

Other factors affecting the potential impact on water quality are the products of weathering resulting from (1) increased area of bitumen exposed and (2) wasting of coal and of oil shale known to be associated with some tar sands. Exposure of coal containing pyrite leads to formation of iron sulfate and in the case of oil shale weathering of organic components leads to the formation of organic acids.

Site specifics that will influence potential for water quality impacts include geochemistry of overburden; pH and redox potential of waters; climate, particularly preciptation; terrain; and geohydrology. Adherence to environmentally sound mining practices, including burial of wasted coal, oil shale, low-grade tar sand, and spent sand as quickly as possible, will reduce whatever potential that might exist.

The same can be said for any measures taken to prevent erosive action of water on bared surfaces and/or to use sedimentation basins, either of which would reduce the potential of contaminants being transported as colloidal or suspended solids or by adhering to suspended inert mineral particles.

Based on the preceding discussion, potential sources of effluents that could be associated with a surface mining operation are precipitation runoff from the mining area, infiltrated water, and effluents from spent sand tailings ponds and processing facilities. Characteristics of effluents expected from a hot water extraction and from a tar sand oil upgrading facility are discussed in a subsequent section. Collectively, these sources, within an effluents guideline perspective, would contain the following constituents:

- BOD
- COD
- TSS
- Oil and grease
- pH
- Phenolic compounds
- Ammonia as N
- Sulfur compounds
- Metals
- Solids.

Surface Changes--

Surface mining of tar sands would change the topography of the land surface through the stripping and excavation of overburden and ore, the construction of haul roads, and the disposal of waste materials. Vegetation on stripped areas, areas graded for facilities (e.g., power lines, roads, and colocated extraction and upgrading plants), and nonstripped areas used for disposal of solid wastes and for impoundments would be destroyed. Collectively, topographic changes, denudation of vegetated areas, and noise from mining (equipment and blasting) can impact wildlife and wildlife habitats.

Surface topography could be restored in part with degree of restoration dependent upon terrain. Efforts to revegetate areas would meet with varying degrees of success depending on availability of top soil, mining practices, terrain, and climate. More generally, factors determining the degree to which the area of a tar sand mine can be restored to a premined status should not differ from those of a surface coal mine in the same area with one significant exception; namely, reclamation and revegetation of spent sand waste disposal areas. Approaches to restoring an area of a tar sand mine to a premined status will have to address problems of restoring areas used for disposal of spent sand from a bitumen extraction plant. Depending upon specifics of an operation, e.g., present or possible future regulations, terrain, extraction process, and method of transporting spent sand to a disposal area, methods of disposing of spent sand will likely include:

(1) Temporary disposal in ponding areas until the sand can be disposed of permanently in mined out areas without interfering with mining operations

(2) Permanent disposal behind dams constructed in valleys near a mine or processing plant.

Revegetation of spent sand disposal areas has been the subject of continuing research at the GCOS operation in Canada. Attendant problems at that operation include those of poor settling properties of clay particles and other fines in the tailing ponds and of minor amounts of bitumen in the tailings which has precluded recycling of water back to the processing plant. Reports are that GCOS has spent at least $1.5 million in research on this problem and that it would cost up to $1.75 per barrel of recovered oil to get the fines to settle out of the water completely.(18)

Ground Water--

Previously discussed surface sources which might degrade quality of surface waters would also be potential sources for impacting ground water quality. Possible transport mechanisms include infiltration of precipitation runoff as it moves downgradient after being in contact with the surface source, precipitation seeping downward through the surface source with resultant leachate entering the groundwater, and process effluents (from adjacent processing facilities) that follow either of these two routes.

In addition to characteristics of the surface sources, potential for impact would depend on the amount and time distribution of precipitation, geohydrological and geochemical parameters, and distance the groundwater travels before it recharges surface streams or is withdrawn for use. With regard to the latter, shallow wells (used for watering livestock) in alluvial aquifers are relatively common in intermittent or dry stream beds in remote and semiarid areas. Quality of water in these aquifers that supply wells downgradient from a nearby tar sand mine probably would present the most immediate potential for being affected.

Potential physical effects of surface mining on groundwater are traceable to two basic causes either, both, or none of which could occur at a specific mine. If the mine intersects an aquifer or aquifers, then groundwater supply to wells, at least to those located immediately downgradient, could be interrupted or diminished. Wells supplied from perched water tables or alluvial aquifers in intermittent or mostly dry stream valleys would be especially susceptible to this type of an effect.

The second cause stems from changes in runoff coefficients resulting from alteration in surface characteristics controlling the amount of precipitation that infiltrates as a local source for charging an aquifer.

IN SITU PRODUCTION

Up to 90 percent of the tar sands deposits in the United States have been estimated to be at depths greater than 300 feet.(3) *In situ* production methods are potentially applicable for recovering bitumen in tar sand deposits that are too deep for surface mining methods to be economically feasible. Where used, these methods would obviate several sources of potential environmental problems associated with surface mining, e.g., disturbing large surface areas, removing overburden, mining and transportation of ore, generation of dust, extraction of the bitumen from the sand, and transportation and disposal of spent sand.

The technology for *in situ* production of tar sands is not as developed as that for surface mining and has not been proven commercially or demonstrated to be economically feasible. The technology is still focused on the experimental and field pilot study phases. *In situ* production would not yield as high a bitumen recovery as would surface mining. Recovery efficiencies of around 90 percent can be expected from surface mining, whereas *in situ* recovery efficiencies probably would range up to approximately 50 percent.

General Methods and History of In Situ Production

In situ production of a tar sand reservoir would require drilling one or more wells into the pay sand, setting casing, and perforating the casing in the potentially productive pay zone. Because of the highly viscous nature of the tar sand bitumen, *in situ* techniques for its recovery would differ from those generally employed for conventional oil recovery. The viscosity of the bitumen must be reduced to a level that will enable it to flow through the sand matrix to the well bore. This may be accomplished by injecting hydrocarbons, solvents, or emulsifiers into the reservoir to dissolve the bitumen and thereby reduce its viscosity, or by adding heat directly by the injection of steam or indirectly by air injection and combustion of part of the bitumen in place. The addition of liquid solvents and emulsifiers has generally proven to be more costly, slower, and less effective than thermal methods of recovery, and most research and field testing has emphasized either direct or indirect thermal recovery. One reason for the apparent advantage of thermal techniques over solvent techniques is the rapid decrease in bitumen viscosity with increases in temperature, e.g., a 5° API tar sand oil found in California has a viscosity of 38,000 centipoises (cp) at 140° F, 1050 cp at 210° F, and only 57 cp at 325° F.(27)

In situ production of a tar sands reservoir would involve using some of the wells to inject the heat or fluid into the reservoir and other wells to produce the bitumen. To improve areal sweep efficiencies, flood patterns would be employed to direct the injection fluid, or heat front, to central producting wells; some commonly used flood patterns are line drive, 5-spot, 7-spot, and 9-spot.

Pilot field projects to develop *in situ* methods for producing tar sands have been conducted intermittently in the U.S. for about 2 decades but, to date, no U.S. or Canadian deposits have been commercially produced by these methods. In 1959-1960, Standard Oil of Ohio tested steam flooding in Utah's Northwest Asphalt Ridge deposit; Shell and Signal Oil (1965-1966) experimented with steam flooding in Utah's Sunnyside deposit; and Gulf, in the 1960's, conducted a fire flood experiment in Utah's Asphalt Ridge deposit. Experiments have also been carried out in Kentucky and western Missouri deposits and pilot tests to produce viscous oil from California's Vacar Tar Sand were conducted by American Petrofina in the mid-1960's using cyclic steam injection.

The most recent field test(15) in the United States was conducted by ERDA's Laramie Energy Research Center on a 9-spot reverse combustion fire flood near Vernal, Utah, on a Sohio lease at Northwest Asphalt Ridge. The fire flood burn was started in November, 1975, and was terminated after only 4 weeks because of poor area sweep efficiency.

At present, there is no evidence of other recent tar sand production field test projects in the United States. A considerable number of pilot and commercial scale projects have been conducted, however, in several states for the production of viscous heavy oils. Since the early 1950's, over 100 *in situ* projects to recover heavy oils have been reported in the literature.

In Canada, *in situ* research efforts have been conducted by Imperial Oil, Shell Canada, Amoco Canada Petroleum, and Gulf Canada. Imperial Oil has spent over $15 million(26) on a research and pilot project to test steam-injection recovery techniques for heavy oil at its Cold Lake facilities. Shell Canada has conducted steam injection tests on the Peace River oil sands deposit, and Amoco is continuing tests of a 50-bpd pilot plant at tar sand deposits near Fort McMurray. Gulf Oil has recently been given approval by the Alberta Energy Resources Conservation Board for a 50-bpd steam-driven pilot test at the Wabasco tar sands deposit.(18)

Most in situ production development, to date, has been conducted on the heavy oil deposits. These heavy oils are similar in composition to tar sands bitumen but have some degree of mobility. The general rule of thumb for distinguishing between heavy oils and tar sands bitumen is that heavy oils will flow at a very low rate, e.g., one barrel per day, whereas tar sand bitumen will not flow at all at reservoir temperatures. The basic technologies employed for producing heavy oils are, however, potentially applicable to the less mobile tar sands bitumen. The specific in situ production technologies that are discussed below are either currently, or have been, applied to tar sand and heavy oil deposits in the United States and Canada.

Specific Methods of In Situ Production

Most information on specific processes and field-test results was obtained through a search of technical journals and reports, reprints of presentations at meetings and symposia, and telephone communication with persons familiar with in situ production methods. In most cases, the technical content of environmentally-related information was neither explicit nor quantitative. Little information was available on the economics of the processes or the analysis of the coproduced streams, e.g., produced water and produced gas. The characteristics of coproduced streams are thus presented only on a generic basis.

Chemical Injection--

Chemical injection involves the injection of hydrocarbon-based solvents or aqueous alkaline surfactants into the producing zone to lower the viscosity of the heavy oil or bitumen. Solvent stimulation using naphthenes and aromatics has been practiced successfully in California since the mid-'60's for the recovery of heavy oils. The process served principally as a well-bore stimulation technique in which the solvent was injected into the zone around the well bore to dissolve the heavy oils and paraffins. In one test, after injecting 500 to 1,000 barrels of solvent, the well was placed back on production.(27) The process was repeated until most of the crude oil in the well-bore vicinity has been produced.

In tests conducted by the USBM near Bartlett, Kansas, in the early 1970's, explosive fracturing of a heavy oil reservoir was followed by solvent stimulation. The experiments met with moderate success; about 12 percent of the oil contained within a 3-spot well pattern was produced.(27)

The application of solvent stimulation or miscible drive displacement for tar sands, however, has not been successful. Shell Canada(29) experimented for several years on the Athabasca tar sands and concluded that viscous fingering and gravity overlay effects, coupled with the high cost of the naphthenes and aromatic solvents, rendered the process economically infeasible. At present, there appears to be no activity, either in the United States or Canada, directed toward the use of miscible solvents to produce tar sands.

Shell Canada developed an alternative to miscible solvent injection that utilizes aqueous-based emulsifying fluids. The emulsifiers were believed to be superior to the miscible fluids in that the oil-loaded emulsifying fluid possessed a viscosity only slightly greater than the original emulsifying fluid and lower than the viscosity of a comparably loaded solvent-based fluid. Moreover, the flow of the injected emulsifiers occurred in the wetting phase path, meaning the bank of tar or heavy oil ahead of the displacement did not have to be moved to obtain penetration into the zone. Two systems were formulated for use in the Athabasca tar sands: (1) an alkaline solution of proprietary nonionic surfactants and (2) a dilute solution of sodium hydroxide. Field testing indicated that the contacted portion of the reservoir was limited to where high gas or water existed, or where a fracture was created. The result was that penetration and dissolution of the tar into the oil was a very slow process and the concept was abandoned.

Steam Injection--

Cyclic Steam Injection--Cyclic steam injection has found wide commercial application since its introduction in 1959 for the production of heavy oils. In this method, steam is injected into a producing zone, followed by an alternate period of production from the same well. The method takes advantage of the high latent heat of vaporization of the steam which, upon condensation, is transmitted to the reservoir. The steam heats the reservoir in the vicinity of the well bore and thus reduces the oil viscosity, permitting the oil to flow during the production cycle.

Development of a cyclic steam injection project entails drilling several closely spaced wells into the reservoir and injecting anywhere from 1,000 to 25,000 bbl of 500° to 700° F steam into each well.(30) The injection process generally lasts a few days after which the wells are shut-in to allow time for the reservoir to "soak". The wells are then opened and produced. The cycle may be repeated several times before the oil production rate diminishes to an uneconomical level.

Cyclic injection has been used successfully in major heavy oil fields in the United States, particularly California. The viscosities of the oil, at reservoir condition, are, however, relatively low (less than 40,000 cp).(31)

Imperial Oil, Ltd.(32) has invested $15 million in a 5,000 bpd project at Alberta's Cold Lake oil sands (100,000 cp at reservoir conditions). Wells are drilled in a 7-spot pattern and steamed for about a month, after which time they are produced on pump for 3 to 4 months. About 30,000 barrels of 600° F steam are injected into each pattern yielding a production of 9,000 to 10,000 barrels of oil for a recovery of 20 to 30 percent of the oil in place.(26) Produced water is separated from the oil by conventional methods and reinjected into a deep formation for disposal. The produced gas, at present, is separated from the produced liquids and flared or reinjected with the steam. No information was available on the exact composition of the produced gas, although it contains primarily CO_2 with small quantities of methane and H_2S. The produced water is saline, with 3,000 to 12,000 ppm

NaCl, and somewhat basic with a pH of 8 to 8.5. The somewhat high pH is attributed to the ion exchange process utilized to soften the steam feed water.

Imperial Oil questions the application of steam cycling as an economically feasible method for producing the heavy oils. It was suggested that extensive research will be required to more effectively utilize the steam, improve sweep efficiencies, optimize selection of candidate production zones, and reduce water influx. One major problem is the enormous volume of water required for steam generation and the availability of water. Imperial is currently working on a project designed to process the produced water to make it acceptable to boilers.(32) Another problem with steam cycling is the energy balance; the pilot project requires an equivalent input of one barrel of oil for every three barrels of oil produced.

Cyclic injection is considered to be more suitable to reservoirs with thick pay zones and large volume of oil in place per acre and with wells capable of commercial production without steam injection.(33,34) There is no evidence of cyclic injection having been successfully employed on oil reservoirs with viscosities in excess of 100,000 cp. As this is significantly less than the viscosity of tar sands bitumen (500,000 to 6 million cp), nothing can, as yet, be concluded concerning the probable success of steam cycling for tar sands production.

Steam Flooding--Steam flooding is similar to a conventional water flood except that the injected fluid is steam, or steam with an emulsifier. An illustration of a steam flooding recovery process is shown in Figure 5. Heat losses restrict the distance that the steam front can be propagated through the reservoir and pattern floods are generally used for the development of a field, e.g., 5-spot or 7-spot patterns.

Steam flooding has found frequent application in reservoirs with high viscosity oils and relatively good permeabilities. For oils with viscosities up to 1,000 cp at normal reservoir temperatures, horizontal sweep efficiencies are usually high. However, viscous bypassing may be significant for oils with normal reservoir viscosities greater than 1,000 cp.

Little work has been conducted on steam flooding highly viscous heavy oil and tar sands. The most noted pilot scale work to date was conducted by Shell Canada, Ltd. in the early 1960's on the McMurray tar sands in Alberta, Canada. A 5-spot pattern of wells was drilled, the production zone fractured, and a caustic and steam solution injected into the four corner wells. Although no information was available on the actual volumes of steam and caustic injected or the volumes of oil produced, 0.685 tons (4 bbl) of steam was injected per barrel of oil produced. From the results, Shell concluded that a practical well spacing for a 5-spot pattern would be 4 acres per producing well and with this configuration predicted a possible overall recovery of 50 to 70 percent of the bitumen in place. Due to the high heat requirements for steam generation, Shell also concluded that for a commercial operation to be economically feasible, no more than 0.5 tons (2.9 bbl) of steam should be injected per barrel of oil recovered.(19)

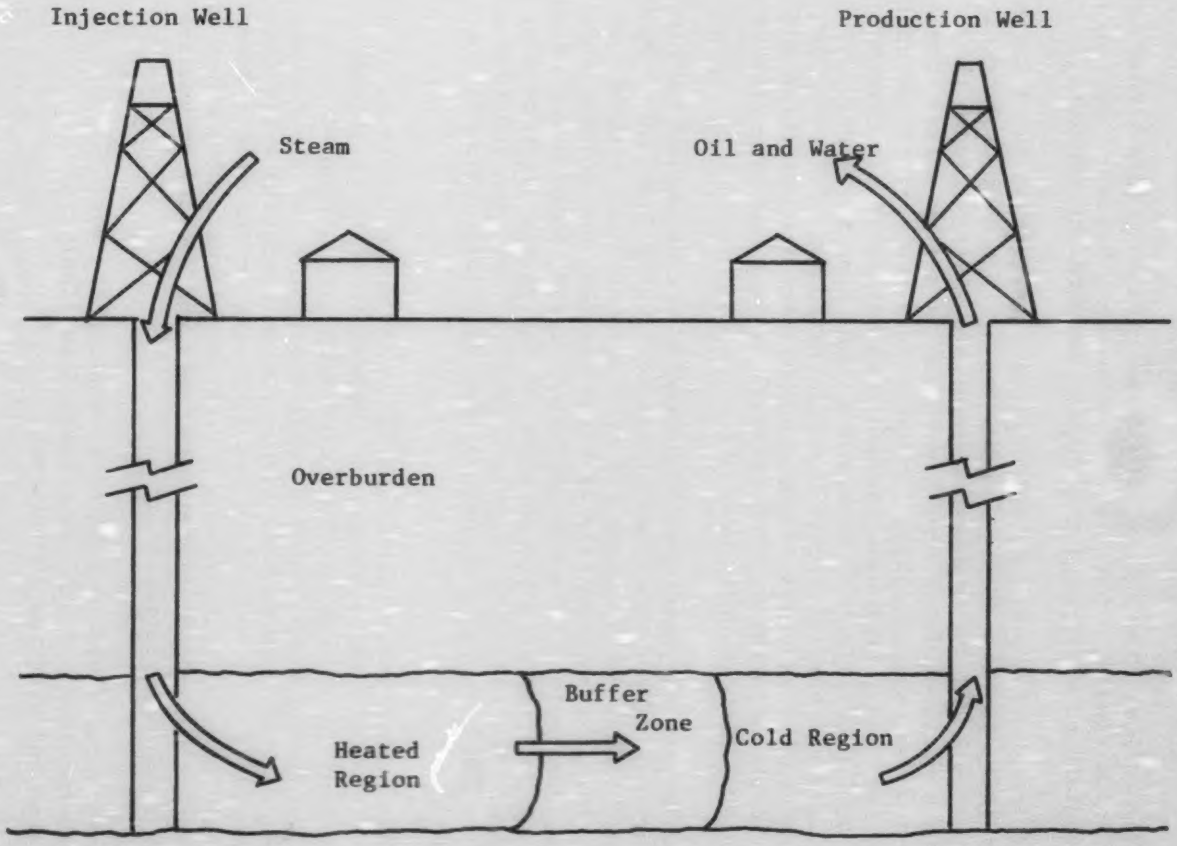

Injection Well
Production Well
Steam
Oil and Water
Overburden
Buffer
Zone
Heated
Region
Cold Region

FIGURE 5 STEAM DRIVE IN SITU RECOVERY PROCESS

Although Shell Canada, Ltd. is continuing to conduct field testing of steam injection on a site in the Peace River oil sands deposit, a commercial steam drive recovery project has not been implemented in either the United States or Canadian tar sands. The major problems associated with steam injection--high energy and water requirements and effective communication between wells--have yet to be solved satisfactorily.

Fireflood--Fireflood involves in situ combustion to generate heat within a formation by combustion of a portion of the in-place bitumen. Principally, there are two variations of in situ combustion--forward and reverse.

The forward combustion process, illustrated in Figure 6, requires the drilling of air injection and oil production wells. Ignition is started at the air injection well and the combustion front propagates through the formation in the direction of air flow toward the producing wells. The temperature of the dry, burned region increases from the temperature of the injected air at the sand face to the maximum temperature at the burning front (600° to 900° F). Injected air captures heat from the burned zone and moves it toward the burning front. Immediately ahead of the burning front, water and light components of the crude bitumen are vaporized and driven toward the producing well. The residual bitumen and coke provide the fuel to sustain the combustion process.

Forward combustion has been applied primarily for secondary and tertiary recovery of heavy oil with viscosities typically ranging from 100 to 1,000 cp at reservoir conditions. The process has been demonstrated, however, to suffer a major drawback, particularly with the heavier more viscous oils in low permeability reservoirs. The oil and water vapors, swept ahead of the burning front, contact the unheated portions of the reservoir where they cool and condense. The condensed liquids become very viscous and tend to plug the pores in which they are deposited thus restricting flow to the production wells.

In a reverse combustion process, also illustrated in Figure 6, ignition is affected in the production well and the combustion front propagates through the tar sand toward the air injection well, i.e., counter to the direction of air flow from the injection well. A portion of the bitumen is vaporized and carried with the air stream to the producing well; the remainder is burned as fuel or left as residual coke in the sand. Reverse combustion has not been utilized to the extent that forward combustion has, although two factors are cited as advantages over the forward combustion process for tar sands application(14):

(1) The vaporized fluids are directed through the hot, burned-out zone and are, therefore, less likely to condense and plug the pore spaces.

(2) The oil produced is of higher quality as a result of the thermal cracking of the bitumen.

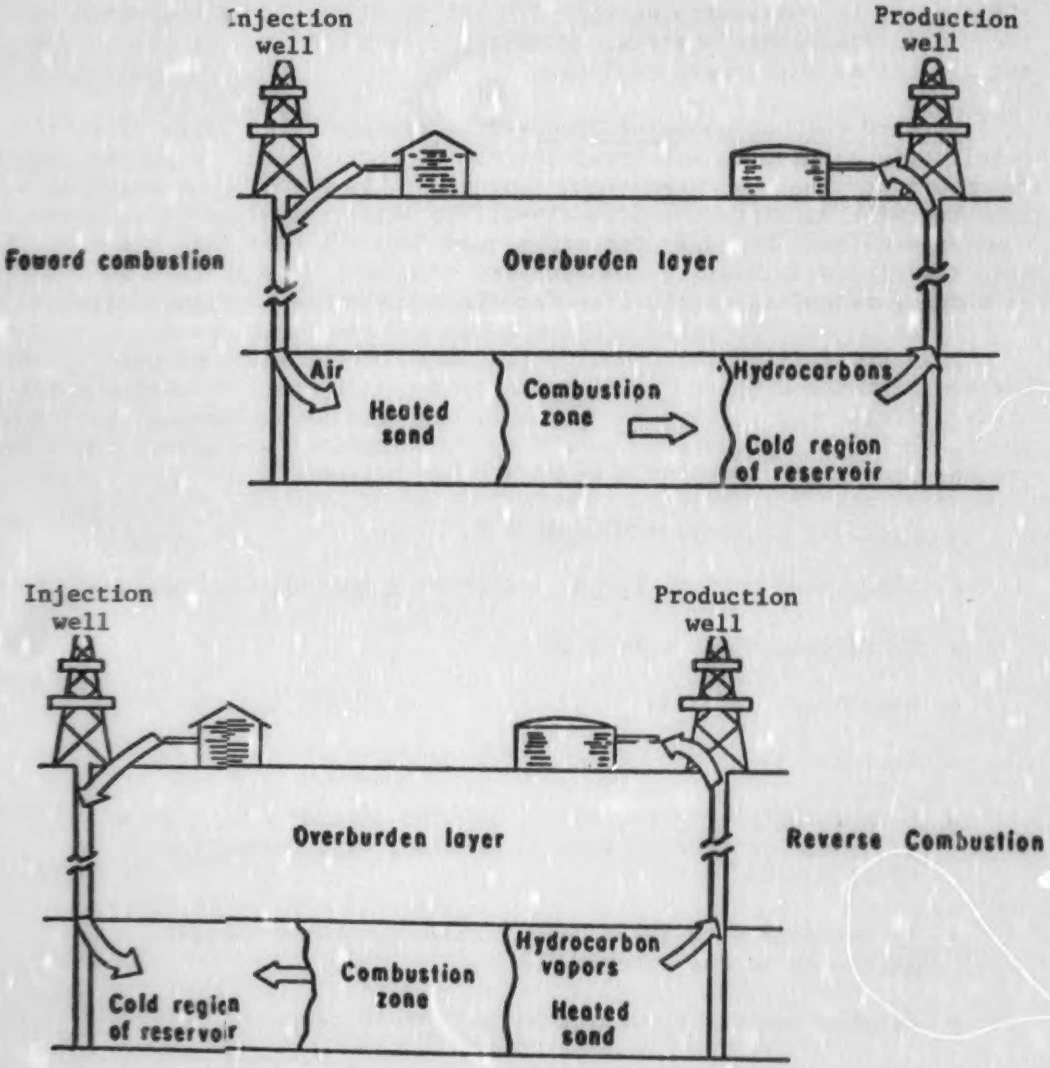

Injection well
Production well
Foward combustion
Overburden layer
Air
Heated sand
Combustion zone
Hydrocarbons
Cold region of reservoir
Injection well
Production well
Overburden layer
Reverse Combustion
Cold region of reservoir
Combustion zone
Hydrocarbon vapors
Heated sand

FIGURE 6. ILLUSTRATION OF FORWARD AND REVERSE COMBUSTION IN SITU RECOVERY PROCESSES (From Reference 14)

The process, however, is sensitive to the air flux, or rate of injection of air, which insures that the burning does not reverse direction and behave as forward combustion.

The most recent reverse combustion experiment was conducted by ERDA/LERC at the Northwest Asphalt Ridge tar sand deposit near Vernal, Utah, in late 1975. Combustion tube experiments indicated that 40 percent of the in-place bitumen would remain in the pay zone as coke and 10 percent would be burned. On the basis of a 50 percent recovery and a 75 percent sweep efficiency, it was estimated that 800 bbl of oil could be recovered from the 9-well line-drive pattern. However, only 55 bbl of upgraded bitumen and 170 bbl of water were recovered.(14,15)

Forward Combustion-Water Flood--This process (see Figure 7) involves instituting a conventional forward combustion drive until a portion of the reservoir has reached a temperature of about 1,500° F, after which water is injected with air into the formation. The water serves to lower combustion temperature, and the generated steam transfers the heat into the formation more rapidly, accelerating the recovery process. This feature is regarded as being particularly attractive for the recovery of tar sands bitumen.(30,35)

To date, most of the research on forward combustion and water flooding has been conducted by the Amoco Production Company in the Athabasca tar sands. Field tests, using conventional and reverse combustion, were commenced in 1958 to produce bitumen from the Gregoire Lake area. Shown below are the properties of the tar sands and the bitumen.

- Specific gravity of bitumen 1.08
- Viscosity (200° F) 1,000 cp (50° F) 2,000,000 to 5,000,000 cp
- Hydrogen/carbon ratio 1.44
- Sand minus 200 mesh
- Porosity 35 to 40 percent
- Permeability most tar zones, 200-300 millidarcies, clean sand from tar zones, several darcies, silt zones, few millidarcies
- Saturations 0 to 90 percent bitumen (remainder water, little or no gas saturation)
- Bitumen content on weight basis 0 to 18 percent.

In 1966, water was injected concurrently with air in a forward combustion drive. The process was labeled the Combination Forward Combustion and Water Flood. Tests performed on a 1/2 acre 5-spot pattern yielded a 32 percent removal of the bitumen in place and it was estimated that 55 percent of the oil heated to 150° F or more was recovered. Following this

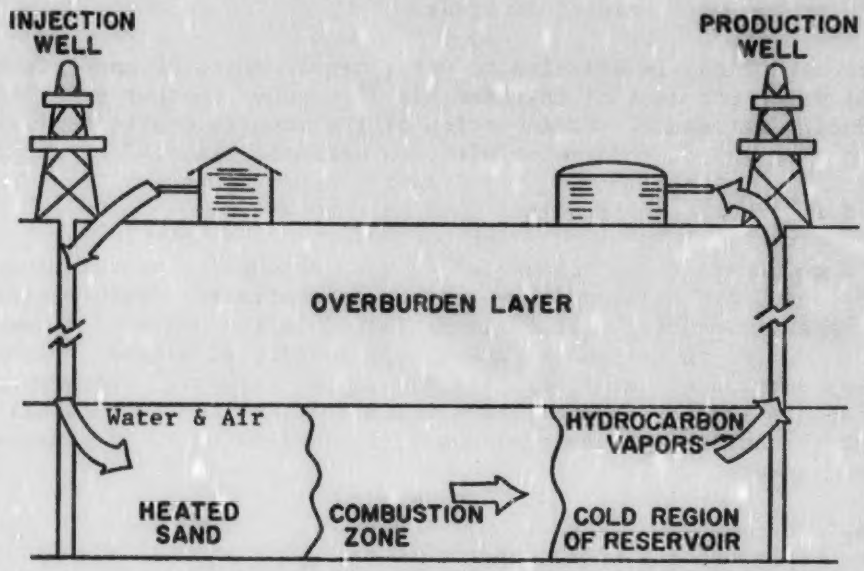

INJECTION WELL
PRODUCTION WELL
OVERBURDEN LAYER
Water & Air
HYDROCARBON VAPORS
HEATED SAND
COMBUSTION ZONE
COLD REGION OF RESERVOIR

FIGURE 7. DIAGRAMATICAL ILLUSTRATION OF A WET FORWARD COMBUSTION IN SITU RECOVERY PROCESS (From Reference 14)

successful operation, an expanded pilot with 12 patterns over 35 acres was developed. Additional tests are currently being conducted.(30)

Forward combustion with water flooding has the advantage over dry forward and reverse combustion in that most of the coke is left in the reservoir as residue, resulting in a less viscous, upgraded produced oil.(37) Recovery efficiencies are also considered to be greater because of improved heat transfer from the steam. In addition, the required volume of injected air is generally lower with the combined water flood. A summary(38) of results from 24 dry forward combustion drives indicated an injected air/produced oil ratio of 6 to 44 mscf/bbl as opposed to a range of 1 to 6 mscf/bbl for two wet combustion drives.

Wet combustion, in addition to water requirements of approximately one barrel of water per mscf of injected air(38), poses another possible problem for producing tar sands. Condensation of the vaporized oils and water could result in plugging of reservoirs with low permeabilities.(37)

Potential Environmental Impacts

To date, there is no commercial in situ production of tar sands and a viable production technology is yet to be demonstrated. Information pertaining to environmental effects is estimated on the basis of a few pilot studies conducted on tar sands and the application of similar technology for the production of heavy oils and is limited at best. Primary environmental impacts should, however, be similar to those of conventional petroleum production and any environmental problems could be addressed in a similar manner.

Air Emissions--

Gaseous byproducts would constitute the major atmospheric discharge associated with in situ combustion. The volumes of gases produced with the oil may vary considerably depending on the reservoir conditions, the type of production mechanism, and the characteristics of the bitumen in place. Gas to oil ratios ranging from 5 to 75 mcf/bbl have been reported from in situ combustion recovery operations.(38)

Generally, the produced gas can be expected to contain varying amounts of sulfur compounds (SO_2, H_2S, etc.), nitrogen, carbon dioxide, carbon monoxide, oxygen, and hydrocarbons. A review(38) of 24 different wet and dry in situ combustion recovery projects on heavy oil reservoirs showed the average range of concentrations of the produced gases to be:

- Oxygen, 2.5 to 3.5 percent
- Carbon dioxide, 10 to 17 percent
- Carbon monoxide, 0 to 2 percent
- Hydrogen sulfide, 0 to 2 percent
- Methane, 0 to 2 percent; and the balance nitrogen.

No information was found on particulates, SO_2, or nonmethane hydrocarbon content.

An analysis(15,37) of the gas produced from the ERDA/LERC reverse combustion test near Vernal, Utah, revealed the following approximate compositions:

- Carbon dioxide, 9 percent
- Carbon monoxide, 3 percent
- Hydrogen, 1 percent
- Methane, 1 percent
- Nitrogen, 80 percent.

There was no evidence of hydrogen sulfide.

Generally, the gases probably would be very lean and lack sufficient heating value to justify collection and processing for marketing. They might be either vented from the water knockout and separation tanks to the atmosphere, or combusted further to completely oxidize the carbon monoxide, hydrogen sulfide, and methane. The ERDA/LERC pilot facility utilized a gas treater with a continuous pilot flame to insure complete combustion of the off gases.(37)

Other air emissions associated with in situ recovery projects are the exhaust discharges from diesel or gasoline-powered equipment and dust generated from vehicles traveling the access roads.

Water Emissions--

The most potentially significant quantity of water from a volume and possible contamination standpoint would be water coproduced with the oil. Some water almost always accompanies produced oil but may vary in quantity from less than 1 percent to over 99 percent of the production stream. No information was found on the composition of the water produced from the tar sands production processes. However, since petroleum and tar sand reservoirs can occur in the same areas, constituent species in the coproduced water probably would be similar to those from conventional petroleum production, an example of which is given in Table 6. Shown in Figure 8, a flow schematic of some of the surface equipment employed in a fire-flood recovery operation, are constituents to be expected in air, solid waste, and water emissions.

Coproduced waters in the conventional onshore petroleum production are not known to present any major environmental problems as the common practice is to reinject them into another subsurface formation. Subsurface disposal of coproduced waters has been practiced in some in situ tar sands pilot projects and is currently being practiced at Imperial Oil of Canada's Cold Lake steam-injection pilot operation.(18)

TABLE 6. RANGE OF CONSTITUENTS IN PRODUCED FORMATION WATER: OFFSHORE CALIFORNIA(a)

Effluent Constituent	Range, mg/l
Arsenic	0.001 - 0.08
Cadmium	0.02 - 0.18
Total Chromium	0.02 - 0.04
Copper	0.05 - 0.116
Lead	0.0 - 0.28
Mercury	0.0005 - 0.002
Nickel	0.100 - 0.29
Silver	0.03
Zinc	0.05 - 3.2
Cyanide	0.0 - 0.004
Phenolic Compounds	0.35 - 2.10
BOD_5	370 - 1,920
COD	340 - 3,000
Chlorides	17,230 - 21,000
TDS	21,700 - 40,400
Suspended Solids	
Effluent	1 - 60
Influent	30 - 75
Oil and Grease	56 - 359

(a) Some data reflect treated waters for reinjection. [From Reference (39)]

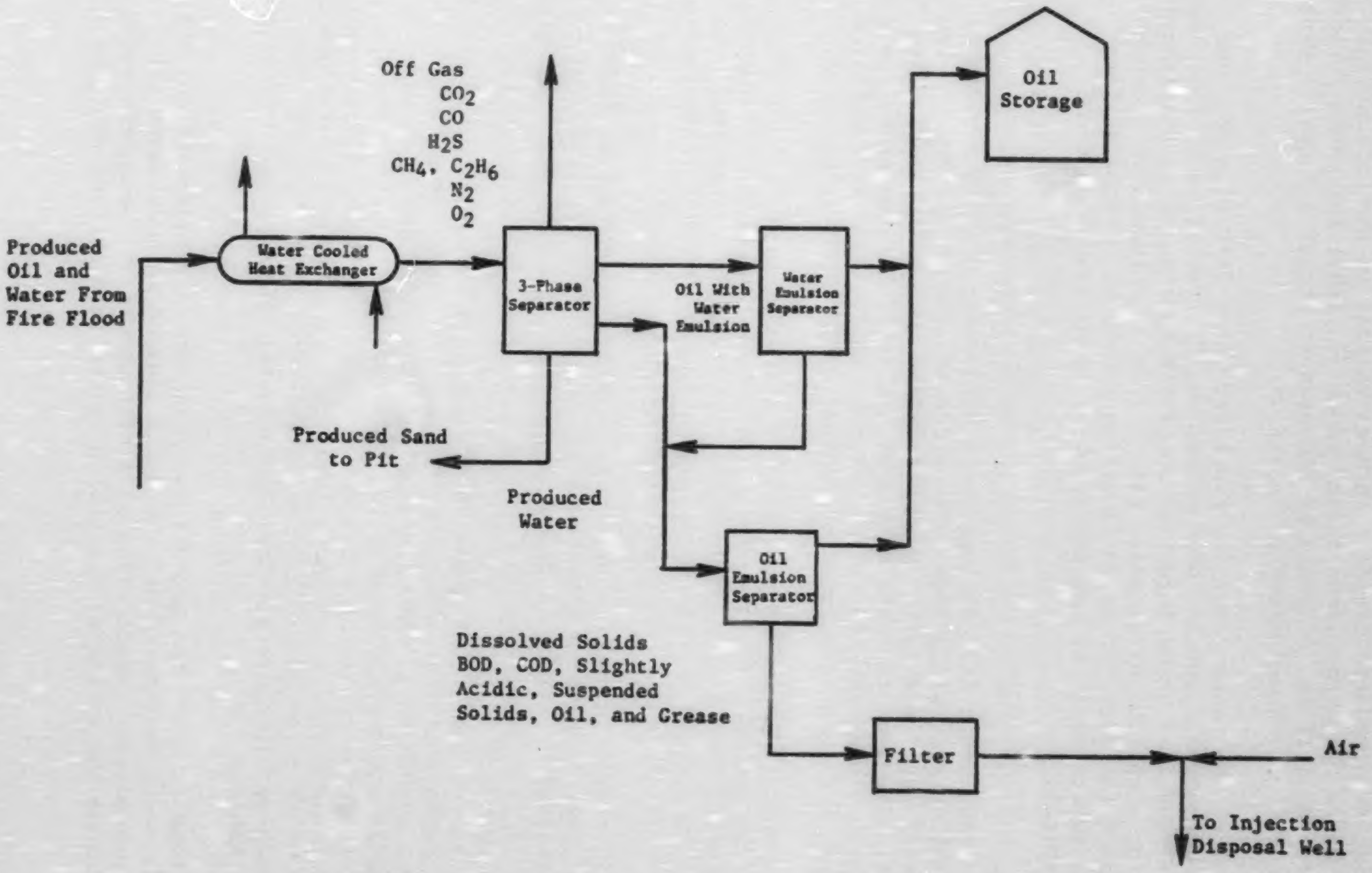

Produced Oil and Water From Fire Flood
Water Cooled Heat Exchanger
Off Gas
CO_2
CO
H_2S
CH_4, C_2H_6
N_2
O_2
3-Phase Separator
Produced Sand to Pit
Produced Water
Oil With Water Emulsion
Water Emulsion Separator
Oil Storage
Oil Emulsion Separator
Dissolved Solids BOD, COD, Slightly Acidic, Suspended Solids, Oil, and Grease
Filter
Air
To Injection Disposal Well

FIGURE 8. FLOW SCHEMATIC OF PROCESS EQUIPMENT IN FIRE FLOOD RECOVERY OPERATION SHOWING VARIOUS EMISSIONS

In *in situ* tar sands production, water would be used primarily for injection into the reservoir (steam flooding and wet combustion processes) and for cooling the produced fluids. In some regions in the United States, particularly where major tar sands exist, water available for these purposes might be a problem. If so, it could be necessary to treat and reuse, rather than dispose of the produced water by injection.

Treatment of the water prior its reuse for water injection in a wet combustion process would involve neutralization, filtration, and flotation; treatment for reuse for steam injection would likely require an additional water-softening step (ion exchange). Figure 9 is a schematic of a water reuse processing facility for steam injection recovery. Potential for environmental impact would be low and somewhat comparable to that of injection disposal.

Solid Wastes--

Produced sand and drill cuttings would constitute the major solid wastes associated with *in situ* production. The produced sand should not be significant if gravel packing or other sand filtration methods are applied in the well bore. The sand that would be produced could be separated from the bitumen and probably discharged into a pit that would later be backfilled. This procedure is commonly employed on conventional onshore production.

The cuttings produced from the drilling operation could also be disposed of by procedures commonly employed in the oil production industry--burying in a pit and back-filling at the completion of the drilling operations. The volume of cuttings would be relatively small; the drilling of a 600-foot well would produce approximately 30 cubic yards of rock cuttings.

Disposal of drilling muds should pose little to no potential for environmental impacts because these muds are customarily collected and reused. Cable tool or air drilling operations do not employ drilling muds.

Surface Changes--

In situ production of tar sands offer much less potential for surface impacts than surface mining. Some vegetation would likely need to be cleared and the ground graded to accommodate equipment installations, but only relatively small areas would be affected. Roads, pipelines, and the appropriate separation and treatment equipment would have to be constructed and electric power and possibly telephone lines erected. Surface operations can be conducted so as to avoid or minimize interference with the concurrent land usage such as livestock grazing, agricultural cultivation, recreation, and wildlife habitat.

At the completion of the production operation, all equipment and the concrete pads could be removed and the wells plugged in accordance with recommended procedures. Restoration of a site should not be an extensive operation because the extent of disruption to the land surface would be minimal.

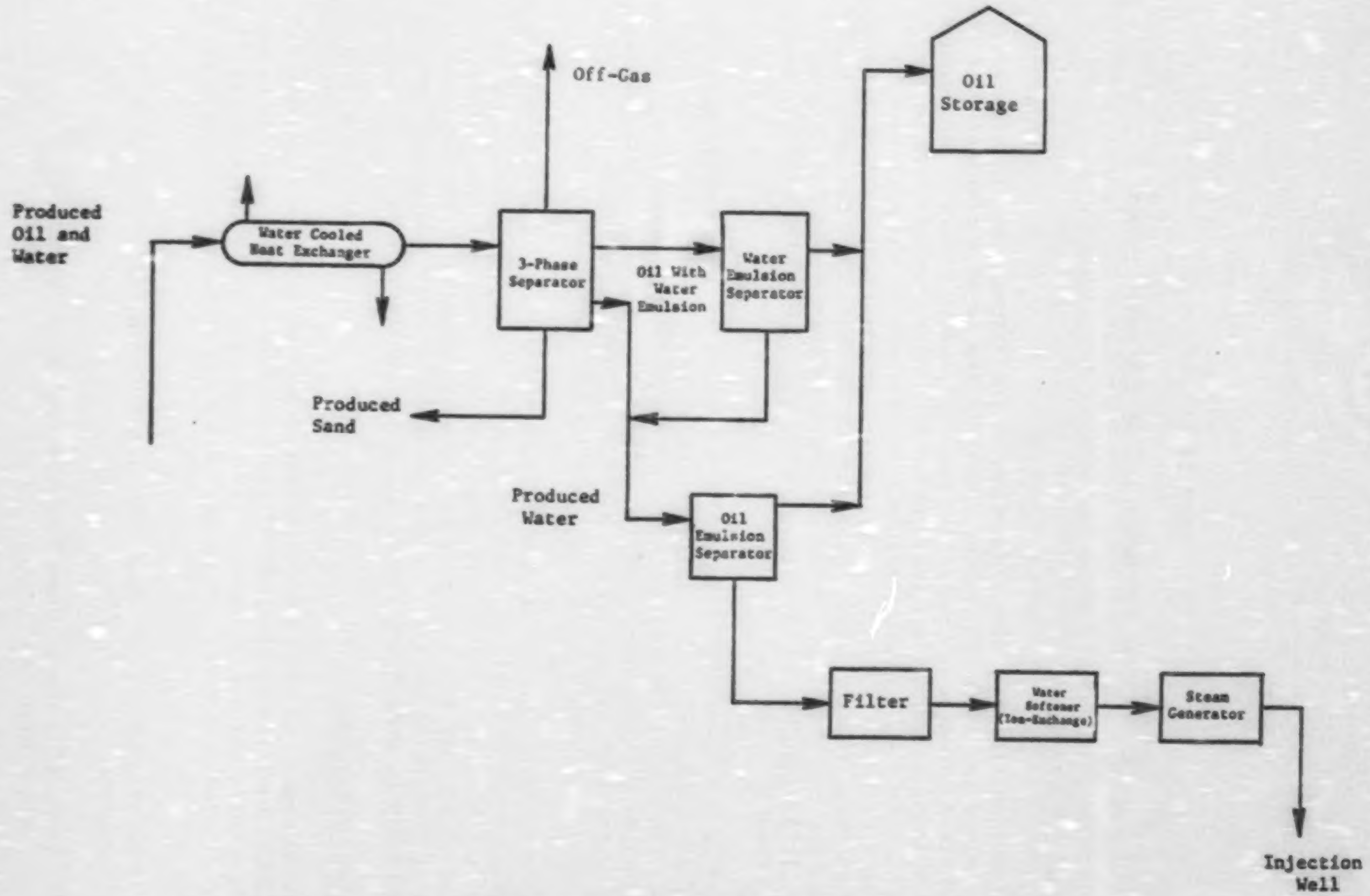

Produced
Oil and
Water
Water Cooled
Heat Exchanger
Off-Gas
3-Phase
Separator
Oil With
Water
Emulsion
Water
Emulsion
Separator
Oil
Storage
Produced
Sand
Produced
Water
Oil
Emulsion
Separator
Filter
Water
Softener
(Ion-Exchange)
Steam
Generator
Injection
Well

FIGURE 9. FLOW SCHEMATIC OF A WATER REUSE PROCESSING FACILITY FOR A STEAM INJECTION RECOVERY PROCESS

SECTION IV

EXTRACTION AND UPGRADING OF TAR SAND BITUMEN

PROCESSING OPERATIONS

Extraction refers to the separation of the bitumen, or tar sand oil, from the mined tar sand. Upgrading refers to the on-site processing of the tar sand oil to produce a synthetic crude oil product suitable for shipment to a petroleum refinery. The final processing into products such as gasoline, heating oil, etc. will almost certainly be done not at the mine site but rather at a petroleum refinery. The complex processing operations necessary to produce these final products would not be economical on the small scale of a U.S. tar sand facility. Even the existing and planned Canadian tar sand facilities, which are much larger than U.S. facilities will be, produce only a synthetic crude oil.

Most of the operations required in the extraction and upgrading of tar sand oil are identical to or similar to operations conducted in petroleum refining. This fact has been used in analyzing the potential emissions from these sections of a tar sand facility. It is also because of this similarity that the extraction and upgrading sections are discussed generally together here. However, separate discussions are provided where appropriate.

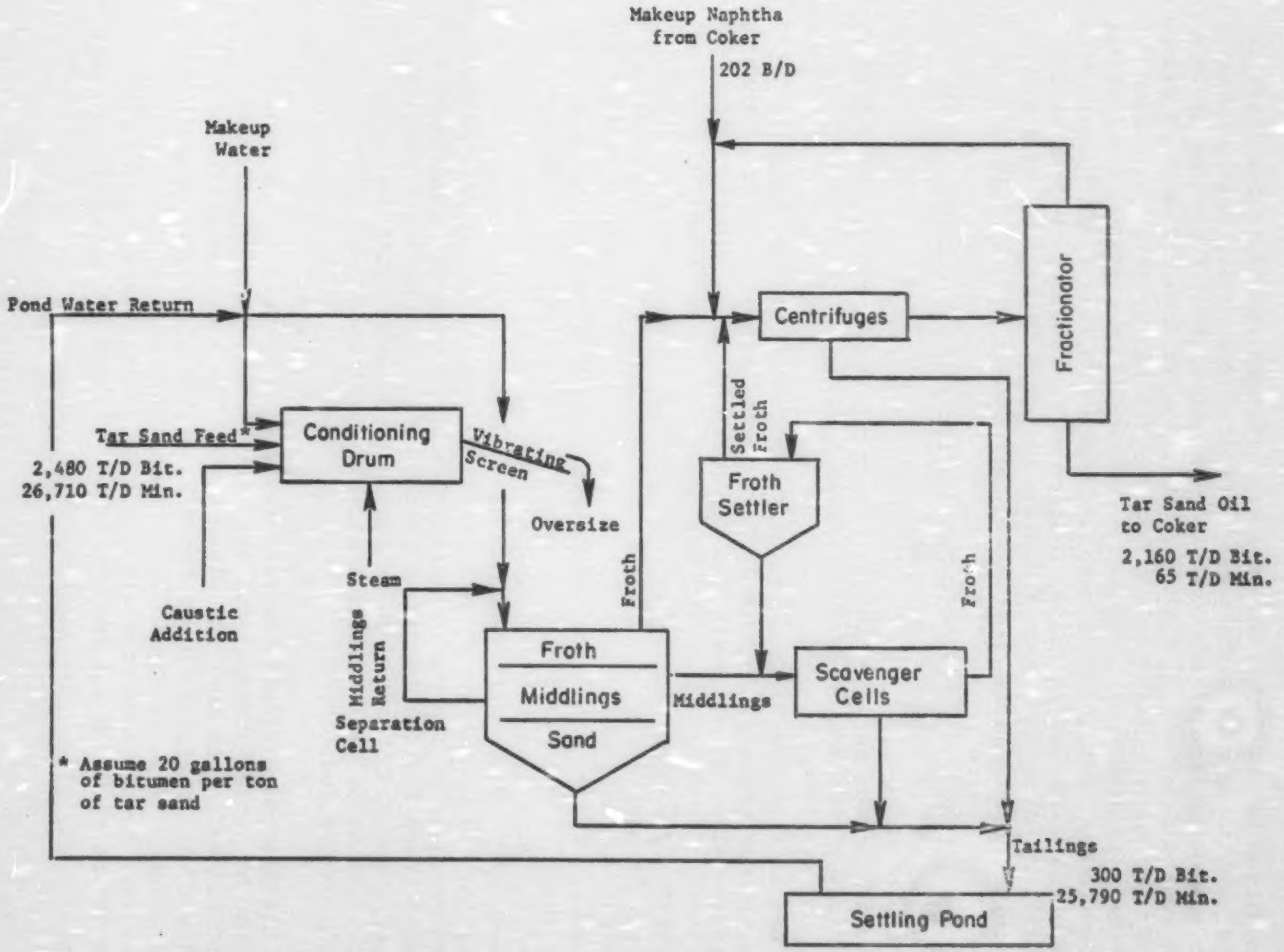
The processing operations selected for the emission analysis were based on a consensus of the one existing and several planned Canadian tar sand facilities. Material balance and emissions data are based on a facility producing 10,000 bbl/day of synthetic crude oil product, which is about the maximum size anticipated for U.S. tar sands.(40) These quantities can, of course, be scaled proportionally to any other facility size.

Extraction Facilities

A flow sheet for the extraction system used at the Great Canadian Oil Sands (GCOS) facility is shown in Figure 10.(18,19) This system is based on the hot water extraction process first developed by Dr. K. A. Clark(41,42) but also piloted by several companies. The extraction sequence includes the following steps:

(1) Pulping of the oil sand with water, steam, and dilute caustic

(2) Separating the bitumen from the sand by skimming and froth flotation


Makeup Naphtha
from Coker
202 B/D
Makeup
Water
Pond Water Return
Tar Sand Feed*
2,480 T/D Bit.
26,710 T/D Min.
Conditioning
Drum
Vibrating
Screen
Oversize
Caustic
Addition
Steam
Middlings
Return
Separation
Cell
Froth
Middlings
Sand
Froth
Middlings
Centrifuges
Settled
Froth
Froth
Settler
Scavenger
Cells
Froth
Fractionator
Tar Sand Oil
to Coker
2,160 T/D Bit.
65 T/D Min.
Tailings
300 T/D Bit.
25,790 T/D Min.
Settling Pond

* Assume 20 gallons of bitumen per ton of tar sand

FIGURE 10. FLOW SHEET FOR TAR SANDS EXTRACTION SYSTEM USED AT GCOS PLANT (QUANTITIES SCALED DOWN TO 10,000 B/D SYNCRUDE PRODUCT FROM UPGRADING SYSTEM)

(3) Mixing the bitumen froth with a diluent (naphtha)

(4) Centrifuging to remove water and fine solids.

In addition to the froth and sand removed from the separation cell, a "middlings" stream is also withdrawn. This stream contains mostly water but also some suspended fine mineral and bitumen particles. A portion of this stream is returned for mixing with the conditioning drum effluent to dilute it properly for pumping. The balance of the middlings, which is called the "drag stream", is withdrawn to purge the system of very fine mineral matter. The drag stream is treated by scavenging, which involves froth flotation using air. The scavenger froth is combined with the settling cell froth, and the tailings from the scavenger cell are combined with the separation cell tailings. The tailings go to a settling pond.

Note that, based on Figure 10, the overall bitumen recovery in the extraction section is about 87 percent.

Other extraction methods that have been proposed for tar sands include cold water separation and anhydrous solvent separation.

Another alternative for separating the bitumen from tar sands is retorting, a high temperature "destructive distillation" similar to that used for oil shale. This alternative has not been given much attention in the literature. In Europe, a Lurgi Ruhrgas process plant used in coal and oil shale retorting experiments has been used in an experiment to distill about 40 metric tons of American tar sand feed stock.(43) A major reason that it might be considered for U.S. tar sands is that it could reduce the water consumption, and Utah's tar sands are located in areas that are generally short of water. The major disadvantage of retorting is that, because of the high temperature required, the thermal efficiency (i.e., oil recovery efficiency) will be lower than for extraction. Also, the quality of the oil product will be inferior because of increased degradation of the hydrocarbons by the high temperatures and increased contamination of the oil with trace species contained in the sand. On the other hand, the lower water consumption should be reflected in a lower water pollution potential. The major solid waste, i.e., the spent sand, should be essentially unaffected.

All the planned Canadian tar sand facilities as well as the operating GCOS include hot water extraction. For that reason, this process was chosen for the emissions analysis given here. The fuel quantities shown on the flow sheet in Figure 10 are based on 10,000 bbl/day of synthetic crude oil product from the upgrading section (discussed below). The quantities were scaled down from the material balance data for the GCOS plant but are based on 20 gallons of bitumen per ton of tar sand feed (see Table 4).

Upgrading Facilities

The raw tar sand oil will be upgraded, probably on-site, to make it more like a typical petroleum crude oil. This will involve

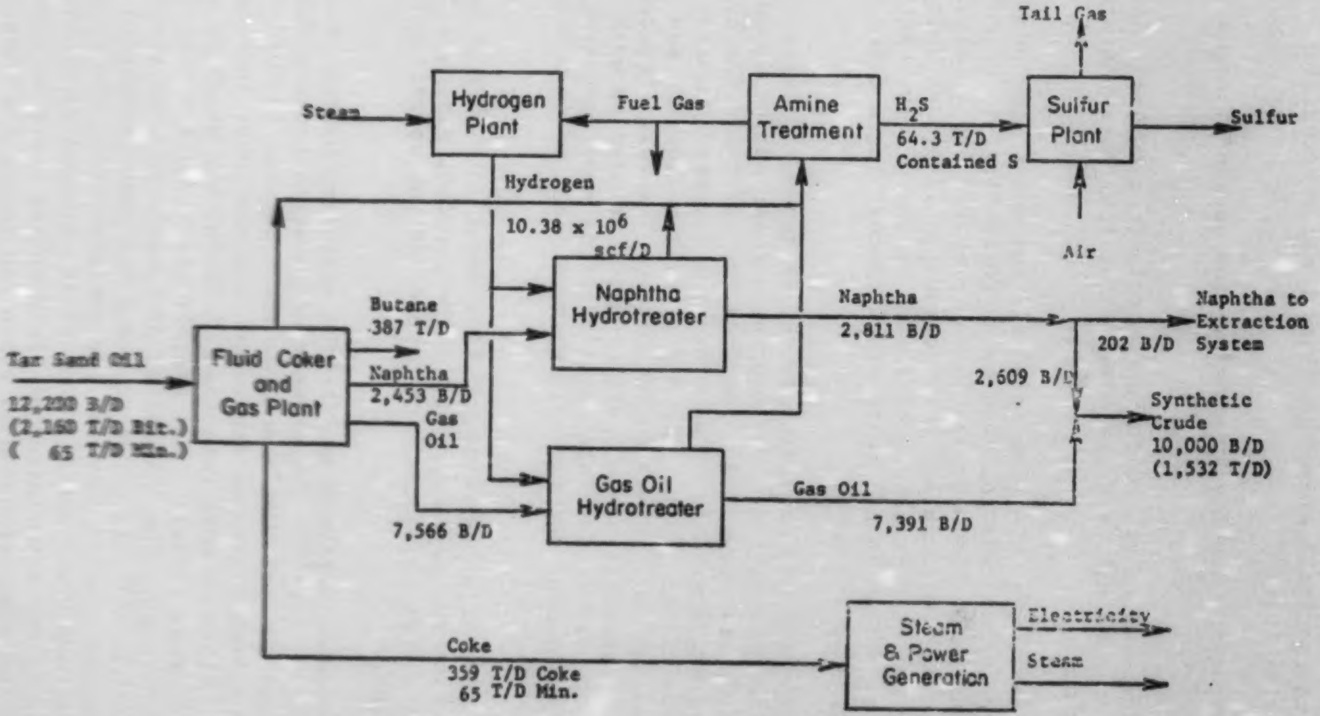
- Removing the small amount of mineral matter remaining in the oil
- Decreasing the density, viscosity, and carbon/hydrogen ratio of the oil
- Removing some of the sulfur and metals from the oil (most U.S. tar sand oil contains more sulfur than most petroleum crudes do).

To accomplish this, the GCOS plant plus all but one of the proposed Canadian plants use a coking process followed by hydrotreating of the coker liquids. The only exception to this sequence is the proposed Shell Canada, Ltd. plant, which is to use vacuum flashing, solvent deasphalting, and hydrotreating.(19) One reason for the attractiveness of coking as the primary upgrading step is that the mineral matter (sand) in the feed cannot plug a coker and is readily removed with the coke.

A flow sheet for the upgrading system is shown in Figure 11. A fluid coker is used in this system. The naphtha and gas oil produced by the coker are hydrotreated separately. Off gas from the coker and the hydrotreaters is freed of H_2S and then used to generate the hydrogen required and to meet other fuel needs of the plant. The H_2S recovered from the gas is converted to elemental sulfur in a Claus sulfur plant. The coke produced by the coker is used to generate steam, part of which is used as such and part of which is in turn used to generate the electrical power required by the plant. The hydrotreated naphtha and gas oil are recombined to form the synthetic crude oil product.

The fuel quantities shown on the flow sheet in Figure 11 were scaled down from the material balance data for the proposed Syncrude Canada, Ltc. plant.(19) Note that the overall oil yield for the upgrading section is about 82 percent.

For comparison, a flow sheet for the upgrading system of the GCOS plant is shown in Figure 12.(19) The primary differences between this flow sheet and the previous one are that a delayed coker is used instead of a fluid coker and three liquid streams are taken from the coker instead of two. Delayed coking produces more coke than fluid coking, which is reflected in a lower liquid product yield. The overall oil yield for this flow sheet is only about 78 percent. The GCOS plant produces more coke than is required for its fuel needs.(44) In order to bring the coke production more in line with the needs and thus to increase the product yield, the future facilities are planning to use fluid coking. One of the planned facilities (Home Oil/Alminex) plans to use a variation of fluid coking known as Flexicoking, in which most of the coker produced is converted into a fuel gas.



Tail Gas
Steam
Hydrogen Plant
Fuel Gas
Amine Treatment
H_2S
64.3 T/D
Contained S
Sulfur Plant
Sulfur
Air
Hydrogen
10.38 x 10^6 scf/D
Naphtha Hydrotreater
Naphtha
2,811 B/D
Naphtha to Extraction System
202 B/D
2,609 B/D
Synthetic Crude
10,000 B/D
(1,532 T/D)
Tar Sand Oil
12,220 B/D
(2,160 T/D Bit.)
(65 T/D Min.)
Fluid Coker and Gas Plant
Butane
387 T/D
Naphtha
2,453 B/D
Gas Oil
7,566 B/D
Gas Oil Hydrotreater
Gas Oil
7,391 B/D
Coke
359 T/D Coke
65 T/D Min.
Steam & Power Generation
Electricity
Steam

FIGURE 11. FLOW SHEET FOR TAR SAND OIL UPGRADING SYSTEM (FUEL QUANTITIES SCALED DOWN FROM SYNCRUDE, CANADA FLOW SHEET)

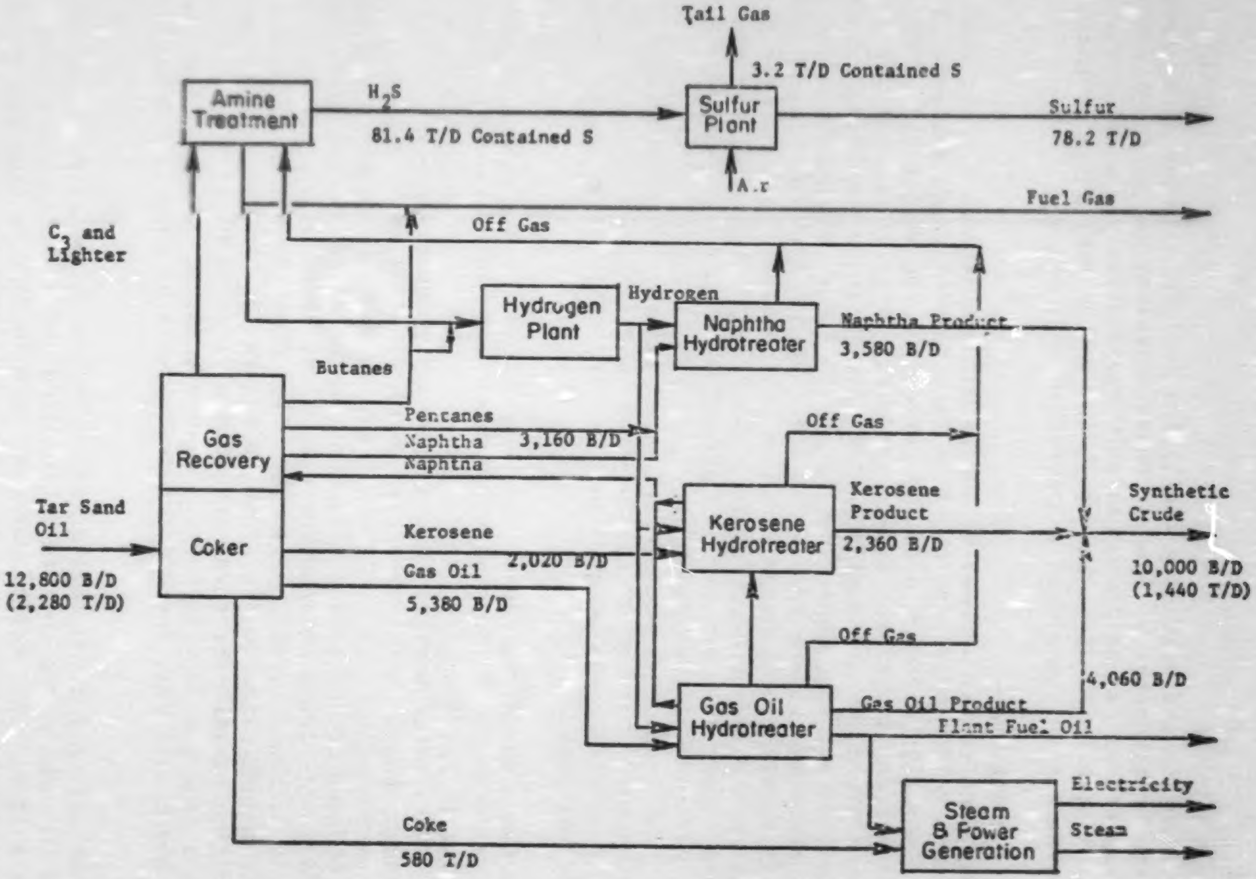

Tail Gas
3.2 T/D Contained S
Amine Treatment
H_2S
81.4 T/D Contained S
Sulfur Plant
Air
Sulfur
78.2 T/D
Fuel Gas
Off Gas
C_3 and Lighter
Hydrogen Plant
Hydrogen
Naphtha Hydrotreater
Naphtha Product
3,580 B/D
Butanes
Gas Recovery
Pentanes
Naphtha 3,160 B/D
Naphtha
Off Gas
Kerosene Hydrotreater
Kerosene Product
2,360 B/D
Synthetic Crude
10,000 B/D
(1,440 T/D)
Tar Sand Oil
12,800 B/D
(2,280 T/D)
Coker
Kerosene
2,020 B/D
Gas Oil
5,380 B/D
Off Gas
4,060 B/D
Gas Oil Hydrotreater
Gas Oil Product
Plant Fuel Oil
Electricity
Steam
Steam & Power Generation
Coke
580 T/D

FIGURE 12. FLOW SHEET FOR TAR SAND OIL UPGRADING SYSTEM USED AT GCOS PLANT (QUANTITIES SCALED DOWN TO 10,000 B/D OUTPUT)

The flow sheet based on fluid coking (Figure 11) should be more representative of future tar sand facilities and hence was used in the calculations presented here.

POTENTIAL ENVIRONMENTAL IMPACTS

Air Emissions

The extraction and upgrading facilities include a number of sources of emissions to the atmosphere. Some of these emissions can be roughly quantified, whereas others can be discussed only qualitatively. Some of the emission estimates to be discussed are based on the similarity of these process operations to those used in petroleum refineries.

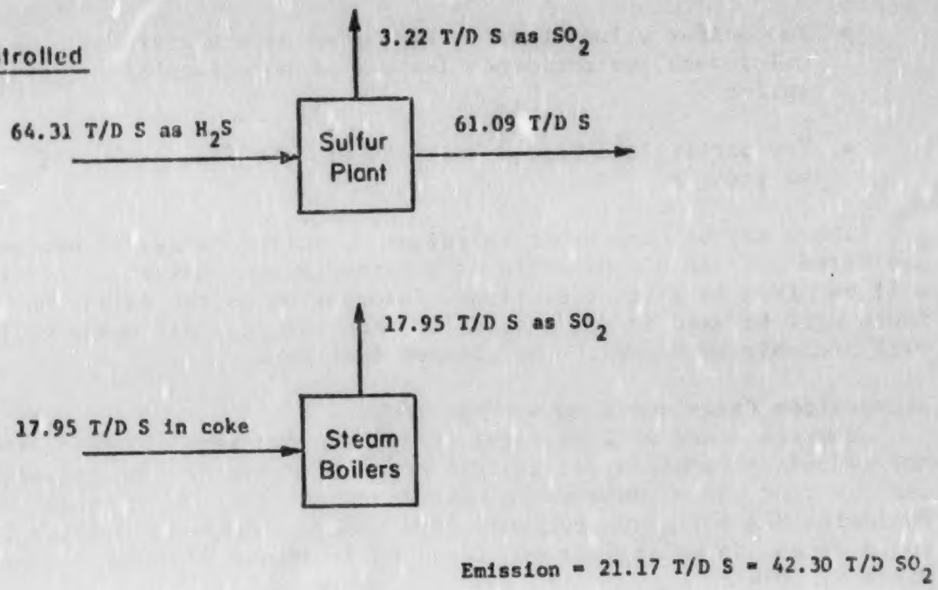
Sulfur Oxide Emissions--

The major potential sources of sulfur oxide emissions are the tail gas from the Claus sulfur plant and the flue gas from the steam boilers. A Claus plant normally recovers about 95 percent of the sulfur fed to it, and the other 5 percent is present as SO_x (primarily SO_2) in the tail gas. Tail gas treatment processes are available that can increase the overall sulfur recovery to 99.5 percent, thus reducing the tail gas emission by a factor of 10. An even more severe problem is the flue gas from the steam boilers, which are fired with the coke produced by the coker. If the feed to the coker contains 4 weight percent sulfur, the coke produced will contain about 5 weight percent sulfur.(45) Combustion of such a high sulfur coke results in considerable emissions of SO_x in the flue gas. Flue gas desulfurization (FGD) processes are available, or at least being developed, that can remove up to 90 percent of the SO_x from flue gas. Actually, the same SO_2 recovery process could be used for both the boiler flue gas and the Claus plant tail gas.

To estimate the magnitude of these emissions, sulfur balances were made for a tar sand oil (to the upgrading section) containing 4 weight percent sulfur. This is the average concentration for the large deposits in southeast Utah. The sulfur content of the syncrude product was taken as 0.27 weight percent, based on the Syncrude Canada data(19), and that of the coke was taken as 5 weight percent. Then, based on the flow sheet in Figure 11, of the 86.40 tons/day of sulfur entering the upgrading section with the feed, 4.14 tons/day will leave in the syncrude, 17.95 tons/day will go into the coke, and 64.31 tons/day will go to the Claus plant as H_2S. Two sulfur balances from that point on are shown in Figure 13. Without a flue gas desulfurization system, the total emission will be about 42.3 tons/day of SO_2. With a flue gas desulfurization system treating both the flue gas and the Claus plant tail gas, the total emission will be about 4.4 tons/day of SO_2.

Another option for controlling sulfur oxide emissions from the steam boilers is to combust the coke in a fluidized bed with limestone added to tie up the sulfur. This method would be as effective as flue gas desulfurization in reducing the SO_x emissions but would have the following disadvantages relative to FGD:

Uncontrolled


3.22 T/D S as SO_2
64.31 T/D S as H_2S
Sulfur Plant
61.09 T/D S
17.95 T/D S as SO_2
17.95 T/D S in coke
Steam Boilers
Emission = 21.17 T/D S = 42.30 T/D SO_2

Controlled

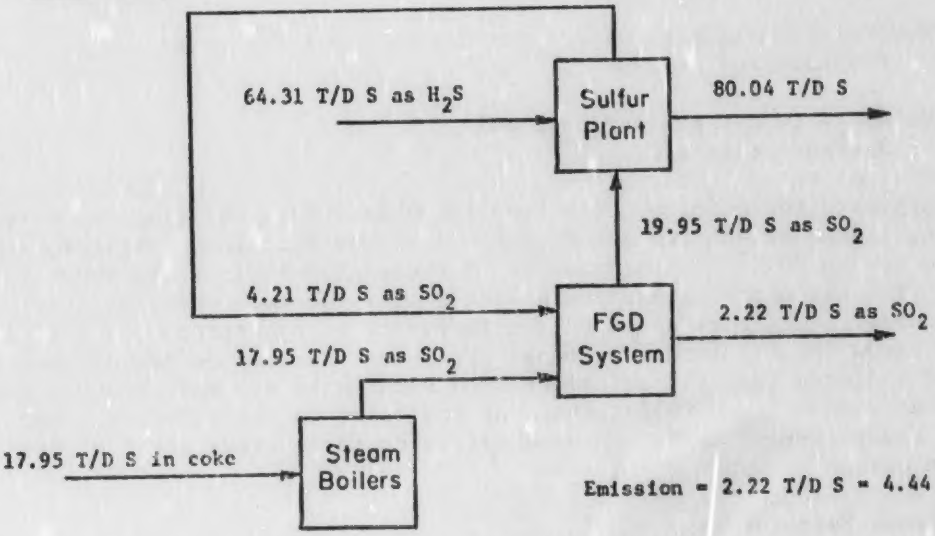

64.31 T/D S as H_2S
Sulfur Plant
80.04 T/D S
19.95 T/D S as SO_2
4.21 T/D S as SO_2
FGD System
2.22 T/D S as SO_2
17.95 T/D S as SO_2
17.95 T/D S in coke
Steam Boilers
Emission = 2.22 T/D S = 4.44 T/D SO_2

FIGURE 13. SULFUR BALANCE FLOW SHEETS FOR TAR SAND OIL UPGRADING SYSTEM
(10,000 B/D Syncrude Product)

- The Claus plant tail gas problem could not be solved simultaneously.

- The sulfur value would be recovered as a mixture of calcium-sulfur compounds instead of as elemental sulfur.

- The particulate matter emission via the flue gas would be greater.

There may be some other emissions of sulfur oxides if process heaters are fired with liquid products or intermediates. Emission factors for this will be given in a later section. Information on the extent to which such fuels will be used is not available. Most of the fuel needs of the plant will probably be met with the cleaned fuel gas.

Hydrocarbon Emissions From Storage Tanks--

Storage tanks will be required for the tar sand oil feed, the naptha and gas oil intermediates, and the syncrude product. The emissions of hydrocarbons from these tanks would depend primarily on the type of tanks used. Following EPA petroleum refinery guidelines, storage facilities required would depend on volatility of stored hydrocarbons (Federal Register 39FR9308, March 8, 1974):

- Nonvolatile (vapor pressure <1.5 psia)
  Cone roof tanks

- Moderately volatile (vapor pressure >1.5 but <11 psia)
  Floating roof tanks

- Volatile (vapor pressure >11 psia)
  Pressure facility.

To estimate the magnitude of these emissions, some calculations were made using the equations developed by the American Petroleum Institute and published by the EPA.(46) The results of these calculations are shown in Table 7. The calculations are for a single tank for each material stored, with the size of the tank based on the flow rate of the stream involved. The data shown for floating-roof tanks apply for the best design of such tanks and indicate that the emissions from such tanks are only about 3 percent of those from fixed-roof tanks. As indicated in the footnote, some types of floating-roof tanks can have emissions three times greater than the "best design" values.

Miscellaneous Emissions--

There are a number of other emission sources in the extraction and upgrading sections that can be roughly quantified based on the similarity of many of the operations involved to operations in petroleum refineries. This can be done by using the published emission factors for the pertinent refinery operations, and these are given in Table 8.(47) The estimated emissions based on these emission factors are shown in Tables 9 and 10.

TABLE 7. HYDROCARBON EMISSIONS FROM STORAGE TANKS

Material Stored	Tar Sand Oil Feed	Naphtha	Gas Oil	Syncrude Product	Total
Tank Size, 10^3 bbl	100	20	50	100	
Tank Dimensions, ft	122 D x 48	63 D x 36	86 D x 48	122 D x 48	
Vapor Pressure at 70 F, psia(a)	5.2	6.6	0.3	3.5	
Specific Gravity(b)	1.011	0.751	0.919	0.860	
Turnover Rate, B input/yr/B capacity(c)	30	13	13	13	
Emissions for Fixed-Roof Tanks, lb/day					
Breathing loss	718	330	53	626	1,727
Working loss	4,000	920	120	2,700	7,740
Total	4,718	1,250	173	3,326	9,467
Emissions for Floating-Roof Tanks, lb/day					
Standing loss(d)	121	66	3	68	258
Withdrawal loss	11	1	3	4	19
Total	132	67	6	72	277

(a) Correspond to Reid vapor pressures of 7.0 psi for tar sand oil feed, 10.5 psi for naphtha, 0.4 psi for gas oil, and 6.0 psi for syncrude product.

(b) Data for proposed Syncrude, Canada plant.

(c) From "Supplement No. 1 for Compilation of Air Pollutant Emission Factors", 2nd Edition, U.S. EPA, July, 1973. Other parameter values taken from this source were tank outage = 50% of tank height, daily temperature variation = 15 F, wind velocity = 10 mi/hr.

(d) For welded tanks. To calculate emissions for completely riveted tanks, multiply by the following factors:

	Single Seal	Double Seal
Pontoon Roof	2.89	2.44
Pan Roof	3.11	2.89

TABLE 8. EMISSION FACTORS FOR PETROLEUM REFINING PROCESSES

Type of Process	Particulate Matter	Sulfur Oxides, as SO_2	Carbon Monoxide	Hydrocarbons	Nitrogen Oxides, as NO_2	Aldehydes	Ammonia
Boilers and process heaters							
$lb/10^3$ ft^3 gas burned	0.02	2s[(a)]	Neg	0.03	0.23	0.03	Neg
$10/10^3$ bbl oil burned	840	6,720 S[(b)]	Neg	140	2,900	25	Neg
Fluid coking units							
Uncontrolled, $lb/10^3$ bbl fr feed	523	NA	Neg	Neg	Neg	Neg	Neg
With ESP, $lb/10^3$ bbl fr feed	6.85	NA	Neg	Neg	Neg	Neg	Neg
Compressor engines, $lb/10^3$ ft^3 gas burned	Neg	2s[(a)]	Neg	1.2	0.9	0.1	0.2
Blow Down Systems							
Uncontrolled, $lb/10^3$ bbl ref cap	Neg	Neg	Neg	300	Neg	Neg	Neg
Controlled,[(c)] $lb/10^3$ bbl ref cap	Neg	Neg	Neg	5	Neg	Neg	Neg
Process Drains							
Uncontrolled, $lb/10^3$ bbl wastewater	Neg	Neg	Neg	210	Neg	Neg	Neg
Controlled,[(d)] $lb/10^3$ bbl wastewater	Neg	Neg	Neg	8	Neg	Neg	Neg
Cooling Towers, $lb/10^6$ gal cooling water	Neg	Neg	Neg	6	Neg	Neg	Neg
Miscellaneous losses, $lb/10^3$ bbl ref cap							
Pipeline valves and flanges	Neg	Neg	Neg	28	Neg	Neg	Neg
Vessel relief valves	Neg	Neg	Neg	11	Neg	Neg	Neg
Pump seals	Neg	Neg	Neg	17	Neg	Neg	Neg
Compressor seals	Neg	Neg	Neg	5	Neg	Neg	Neg
Others[(e)]	Neg	Neg	Neg	10	Neg	Neg	Neg

(a) s = refinery gas sulfur content ($lb/100$ ft^3). Factors based on complete combustion of sulfur to SO_2.

(b) S = fuel oil sulfur content (weight percent). Factors based on complete combustion of sulfur to SO_2 and assumed fuel oil density of 336 lb/bbl (0.96 kg/liter).

(c) Vapor recovery system or flaring.

(d) Vapor recovery or covers on oil/water separators.

(e) Direct air blowing, sampling, etc.

Source: Compilation of Air Pollutant Emission Factors, 2nd Edition, AP-42, pp 9.1-3 to 9.1-5, U.S. EPA, April, 1973.

Conversion factors: kg/liter = 0.002853 (lb/bbl), kg/m^3 = 16.02 (lb/ft^3), kg/liter = 0.1198 (lb/gal).

TABLE 9. UNCONTROLLED EMISSIONS TO AIR FROM TAR SAND OIL UPGRADING SYSTEM

(10,000 bbl/day Syncrude Product)

	Emissions, lb/day						
Process Operation	Particulate Matter	Sulfur Oxides, as SO_2	Carbon Monoxide	Hydrocarbons	Nitrogen Oxides, as NO_2	Aldehydes	Ammonia
Steam plant	2,450(a)	71,733	359(b)	11(b)	6,462(b)		
Sulfur plant		12,850					
Storage tanks (fixed roof)	—	—	—	5,477	—	—	—
Fluid coker	6,381	—	—	—	—	—	—
Blow down systems	—	—	—	3,660	—	—	—
Process drains	—	—	—	1,464(c)	—	—	—
Cooling towers	—	—	—	106(d)	—	—	—
Valves, flanges, seals, etc.	—	—	—	866	—	—	—
Subtotal	8,831	84,543	359	11,584	6,462		
Process heaters							—
Compressor engines	—		—				

(a) Based on 70% of mineral matter in coke feed going into fly ash (30% into bottom ash).

(b) Based on emission factors for anthracite coal in pulverized furnace. For stoker furnace, emissions of carbon monoxide and hydrocarbons would be about 6 times as high and emission of nitrogen oxides would be 16 to 67 percent lower. Source: Compilation of Air Pollutant Emission Factors, 2nd Edition, AP-42, pp 1.1-3 and 1.2-2, U.S. EPA, 1952.

(c) Based on 24 gallon wastewater/bbl oil feed (see Table 11).

(d) Based on 1,450 gallon cooling water circulation/bbl oil feed (see Table 11).

TABLE 10. CONTROLLED EMISSIONS TO AIR FROM TAR SAND OIL UPGRADING SYSTEM

(10,000 bbl/day Syncrude Product)

		Emissions, lb/day						
Process Operation	Controls	Particulate Matter	Sulfur Oxides, as SO_2	Carbon Monoxide	Hydrocarbons	Nitrogen Oxides, as NO_2	Aldehydes	Ammonia
Steam plant	Flue gas desulf (FGD) system	—	8,872	(a)	(a)	(a)		
Sulfur plant	Tail gas recycle to FGD system		0					
Storage tanks	Floating roof	—	—	—	283	—	—	—
Fluid coker	Electrostatic precipitator	84	—	—	—	—	—	—
Blow down systems	Vapor recovery or flaring	—	—	—	61	—	—	—
Process drains	Vapor recovery or covers on separators	—	—	—	56[b]	—	—	—
Cooling towers		—	—	—	106[c]	—	—	—
Valves, flanges, seals, etc.		—	—	—	865	—	—	—
Subtotal		84	8,872		1,372			
Process heaters								—
Compressor engines		—		—				

(a) Depends on type of flue gas desulfurization system used.

(b) Based on 24 gallon wastewater/bbl oil feed (see Table 11).

(c) Based on 1,450 gallon cooling water circulation/bbl oil feed (see Table 11).

Table 9 gives the uncontrolled emissions and Table 10 the controlled emissions. These tables also include the data from the previous sections on sulfur oxide emissions and hydrocarbons storage losses.

The miscellaneous emissions include (Table 9):

- Hydrocarbons from blowdown systems, process drains, cooling towers, and leakage from valves, flages, and seals
- Particulate matter from fluid coker and steam plant
- Nitrogen oxides from the steam plants.

There are also emissions from process heaters and compressor engines. Emissions from the process heaters depend strongly upon whether gas or oil is used to fire the heaters, as can be seen from the emission factors in Table 8.

The emission control methods considered here include (Table 10):

- A flue gas desulfurization system for the steam boiler flue gas and the Claus plant tail gas
- Floating-roof storage tanks
- An electrostatic precipitator on the fluid coker
- A vapor recovery or flaring system for process blowdown
- Vapor recovery systems or covers on the oil/water separators.

These methods result in overall emission reductions of about 90 percent for sulfor oxides, 88 percent for hydrocarbons, and 99 percent for particulate matter. These figures do not include the emissions from process heaters and compressor engines, which could not be estimated.

In order to estimate the emissions from two sources (process drains and cooling towers), information was required on the cooling water circulation rate and wastewater flow rate. Lacking any more specific data, average data for Category B petroleum refineries were used.(48) These data are shown in Table 11. A Category B refinery is one which includes cracking-type processes like coking but not more complex operations such as lube oil or petrochemical production. This concept will be discussed further in the following section on water emissions.

A source of hydrocarbon emissions not shared by petroleum refineries is that of evaporation from the surface of the settling pond used for the tailings. This emission cannot be quantified but will be less than the flow rate of bitumen to the pond (300 tons/day in Figure 10), since some of this bitumen will be returned to the process with the pond water return.

TABLE 11. WATER USE CHARACTERISTICS OF CATEGORY B PETROLEUM REFINERIES

Cooling Water Circulation Rate, gal/bbl crude	1,450
Wastewater Flow, gal/bbl crude	
Refineries with no once-through cooling water	
Median	24
Range	4-89
Refineries with some once-through cooling water	
Median	174
Range	7-6,861

Source: Brown & Root, Inc., "Economics of Refinery Wastewater Treatment", API Publication No. 4199, pp V-2 and V-9, August, 1973.

Conversion factor: kg/liter = 0.002853 (lb/bbl).

Water Emissions

The extraction and upgrading facilities include a number of operations that will generate wastewater at various levels of contamination. Like any other modern plant, a new tar sand facility would be expected to use modern technology for reducing the wastewater flow and for treating the wastewater prior to discharging it. The wastewater problems of a tar sand facility will be very similar to those of a petroleum refinery. The final pollutant emission rates from the facility will depend upon the extent to which the wastewater is treated. Lacking other information, one can roughly estimate the emission rates for a tar sand facility by assuming that such a facility will have to restrict its emissions to about the same level as a modernly controlled petroleum refinery of similar size and complexity. These concepts will be elaborated on in the following sections.

Sources of Wastewater--

Based largely on the experience of petroleum refineries(49), one can say that the sources of wastewater from tar sand oil extraction and upgrading facilities will include the following:

(1) Cooling Water Blowdown. As will be discussed in the following section, the facility will almost certainly use an evaporative, recirculating cooling water system. In such a system, a small amount (usually 0.5-2 percent(45,49)) of the circulating water must be withdrawn to purge dissolved solids from the system. This "blowdown" contains a very high concentration of dissolved solids (usually 0.2-0.4 percent(49)) and small amounts of various species added during treatment of the water or picked up during its use.

(2) Boiler Feed Water Blowdown. The normal practice in plants requiring steam is to recycle the steam condensate for use as boiler feed water. When this is done, a small amount (typically about 5 percent(49)) of this water must be withdrawn to purge dissolved solids from the system. This blowdown is similar in composition to the cooling water blowdown discussed above.

(3) Sour Water. Sour water, containing primarily H_2S and NH_3, will be generated in the fractionation operations that follow the coker and the hydrotreaters. In addition to H_2S and NH_3, the condensate from the coker fractionator will contain phenols and perhaps cyanides. Sour water can also come from process knockout drums.

(4) Storm Water Runoff. The runoff water from paved process areas and tank areas will be oily, whereas that from utility areas will contain solids but not oil.

(5) Pump and Compressor Cooling Water. Some water used in cooling pump pedestals and glands and compressor jackets will become contaminated with oil.

(6) Tank Bottom Draws. The water periodically drained from tanks will be oily and in some cases also sour.

Water Segregation and Reuse System--

In order to minimize the wastewater treatment costs and the final effluent rate, the facilities will employ modern technology for segregating various effluent streams and reusing water. The facilities will almost certainly use a recirculating cooling water system with tooling towers rather than once-through cooling water. Steam condensate will be reused as boiler feed water. Segregating the effluent according to composition will increase the efficiency of the wastewater treatment system, since each effluent will receive only the treatment it requires. For example, only oily waters will go through the API oil-water separators.

Wastewater Treatment Processes--

A combination of wastewater treatment processes will be used in a tar sand facility. These processes probably will be selected from the following:

- Primary Treatment Processes
  - Equalization (to dampen surbes in flow and loadings)
  - API oil-water separators
  - Sour water strippers

- Secondary Treatment Processes
  - Dissolved air flotation
  - Aerated lagoons
  - Activated sludge treatment
  - Chemical coagulation and sedimentation
  - Filtration.

Tertiary treatment processes, such as carbon adsorption, ion exchange, and reverse osmosis, probably will not be used.

Estimated Effluent Rates--

The operations conducted in the extraction and upgrading sections of a tar sand facility, and hence the wastewater problems, will be very similar to those of a petroleum refinery. Therefore, one can use information on petroleum refineries as a basis for roughly estimating the effluent rates for a tar sand facility. To be more specific, one can use data for Category B refineries. This category includes cracking-type or petrochemical production. Two types of data for such refineries can be used--effluent regulations or effluent data--for actual refineries.

In considering effluent regulations, it is most meaningful to consider the New Source Performance Standards (NSPS), since these apply to new facilities such as the tar sand facilities will be. These standards specify the maximum effluent rates, in pounds per thousand barrels of feedstock, for various effluent characteristics (BOD, COD, etc.). The standards depend on the size and complexity of the refinery. The complexity is expressed in terms of a "process configuration" factor, which is six for the flow sheet of interest in which all the feedstock goes through a coker. For a Category B refinery of this complexity and the size range of interest here (up to 24,900 bbl/day), the NSPS are given in Table 12.(50) Also included in this table are the corresponding maximum effluent rates (in pounds per day) for a tar sand facility producing 10,000 bbl/day of synthetic crude oil product.

For comparison with the NSPS, some data on observed effluent loadings for existing Category B refineries are given in Table 13.(51) This table also shows the wastewater treatment processes used at these refineries. For all the effluent characteristics on which data were available, the observed effluent loadings span a fairly wide range (a factor of at least 2.5) and (except for ammonia) go both above and below the 30-day average NSPS.

Some qualitative evaluations of the wastewater-related characteristics of the individual processes used in the extraction and upgrading sections are shown in Table 14.(51) This table indicates the extent to which these processes contribute to the flow rate and various effluent characteristics of the total wastewater.

Solid and Miscellaneous Wastes

The most abundant solid waste material produced by the extraction and upgrading sections will be the mineral matter sent as tailing to the settling pond. For a tar sand facility producing 10,000 bbl/day of synthetic crude oil product, about 25,790 tons/day of mineral matter will be rejected in this manner (see Figure 10). This mineral matter probably will be returned to the mine.

Another 65 tons/day of mineral matter will go the steam boilers in the coke. About 20 tons/day of this material will be recovered from the boilers as bottom ash, and about 45 tons/day will go into fly ash in the flue gas. If only cyclones are used, only part of this fly ash will be recovered. If high efficiency electrostatic precipitators are used, over 99 percent of the fly ash will be recovered. If a flue gas desulfurization system is used, some collection of particulate matter will be done ahead of the FGD system. The mineral matter recovered as bottom ash or fly ash will be relatively easy to dispose of because it will be inert and dry.

A small amount of waste material is produced by the amine treatment operation used for removing H_2S from off gases. This is a purge stream containing primarily amines and various organic compounds produced from amines. The amount of this purge stream is about 1.6 pounds per ton of sulfur recovered from H_2S.(52) Therefore, based on the sulfur balance previously discussed, a facility of the size considered here (10,000 bbl/day) would produce about 100 pounds per day of this material.

TABLE 12. MAXIMUM EFFLUENT RATES BASED ON NEW SOURCE PERFORMANCE STANDARDS FOR PETROLEUM REFINERIES[(a)]

Effluent Characteristic	Maximum Unit Effluent Rate, pounds/1000 bbl feedstock[(b)]		Maximum Total Effluent Rate for 10,000 bbl/day of Synthetic Crude Product pounds, day[(c)]	
	For Any One Day	Average of Daily Values for 30 Consecutive Days	For Any One Day	Average of Daily Values for 30 Consecutive Days
BOD_5	5.75	3.07	70.2	37.5
COD_1	41.16	20.83	502.2	254.1
TSS	3.97	2.48	48.4	30.3
Oil and grease	1.69	0.92	20.6	11.3
Phenolic compounds	0.0417	0.0198	0.508	0.242
Ammonia as N	6.55	2.98	79.9	36.3
Sulfide	0.0367	0.0169	0.448	0.206
Total chromium	0.0833	0.0486	1.016	0.593
Hexavalent chromium	0.00714	0.00317	0.087	0.039
pH (dimensionless)	Within the range 6.0 to 9.0			

(a) Based on Federal Register, 40 (98), May 20, 1975. Standards for Category B refinery with process configuration = 6.

(b) Feedstock is tar sand oil to upgrading. Values apply for up to 24,900 bbl/day.

(c) Based on 12,200 bbl/day tar sand oil to upgrading.

Conversion factors: kg/liter = 0.002853 (lb/bbl), kg/m^3 = 2.853 (lb/bbl), kg/day = 0.4536 (lb/day).

TABLE 13. OBSERVED EFFLUENT LOADINGS FOR CATEGORY B PETROLEUM REFINERIES

Refinery Number	1	2	3	4	5
Wastewater Treatment Processes Employed					
Aerated lagoon	X	X			X
Activated sludge			X		
Dissolved air flotation			X		X
Equalization			X		
Filtration		X			
Oxidation pond				X	
Polishing pond	X				X
Effluent Loadings, lb/1000 bbl feed					
BOD_5	2.8	4.4	2.1	3.6	1.3
COD	13.8	24	34	25.0	13.8
TSS		8.7	12	3.0	1.5
Oil and grease	0.8	3.2	1.4		1.0
Phenolic compounds	0.001	0.145	0.13	0.018	0.002
Ammonia as N				1.7	0.05
Sulfide		0.07	0	0.010	0.005

Source: Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Petroleum Refining Point Source Category, EPA 440/1-74-014a, p 104, April, 1974.

Conversion factor: kg/liter = 0.002853 (lb/bbl).

TABLE 14. QUALITATIVE EVALUATION OF WASTEWATER FLOW AND CHARACTERISTICS. BY FUNDAMENTAL REFINERY PROCESSES

Wastewater Characteristic	Production Process			
	Feed and Product Storage	Distillation	Coking/Thermal Cracking	Hydrotreating
Flow	XX	XXX	X	X
BOD	X	X	X	X
COD	XXX	X	X	X
Phenol	X	XX	X	
Sulfide		XXX	X	XX
Oil	XXX	XX	X	
Emulsified oil	XX	XXX		0
pH	0	X	XX	XX
Temp	0	XX	XX	
Ammonia	0	XXX	X	XX
Chloride		X	X	0
Acidity	0	0	0	0
Alkalinity		X	XX	X
Suspended solids	XX	X	X	0

X - Minor contribution, XX - moderate contribution, XXX - major contribution, 0 - no problem.

Source: Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Petroleum Refining Point Source Category, EPA 440/1-74-014a, p 18, April, 1974.

If a flue gas desulfurization process is used, a small amount of waste material may be produced as a result, depending on the nature of the FGD process. For example, the Wellman-Lord FGD process, which would be well suited to this application, produces a purge stream by which certain oxidation products (e.g., sodium sulfate) are removed from the system. In this case, processing steps can be included so that only a solid waste material is produced. Although the quantity of this sulfate material is small, its high water solubility makes disposal difficult.

SECTION V

ENVIRONMENTAL COMPARISON OF TAR SAND PRODUCTION AND PROCESSING TECHNOLOGY

Information on tar sand production and processing technologies and their potential sources of primary environmental impact have been described in preceding sections. Drawing from that information, the environmental pros and cons of the production and processing technoligies are discussed below and summarized in Table 15.

Surface mining methods for producing tar sands would pose greater potential for environmental impact than underground methods. This greater potential is traceable to problems of restoring larger surface areas disturbed by surface mining to a premined condition, the greater availability of aqueous transportable materials and the restoration of areas used for disposal of spent sand.

All mining methods pose greater potential for environmental impact than in situ methods. This is because tar sands produced by mining methods would require an intermediate process to extract the bitumen from the mined tar sand ore. Thus, the potential impacts of bitumen extraction process would either occur at or in the region encompassing the mining area in the case of a colocated extraction plant or at some other location in the unlikely event that the tar sand ore is transported considerable distances from the mine.

Environmental advantages of wet versus retorting (dry) extraction processes are not as clear cut as in the case of production methods. Both would generate solid waste and some process and/or cooling water effluent with amounts dependent upon provisions for reusing water. Process effluents from wet extraction could contain hydrolyzed components of tar sand constituents which would have to be traded off against the potential air emissions from retorting.

Tar sand oil extracted from the mined tar sand or produced by in situ methods would go to an upgrading facility. In this sense, the potential environmental impacts attributable to upgrading facilities would probably be somewhat independent of production method. However, data on composition of water, gas, and tar sand oil produced by the various in situ methods are extremely meager. The tar sand oil might be transported to an existing coke/hydrotreating facility for upgrading or a new facility constructed. Several factors will determine which of these options is selected, not the least of which is the location and size of the resource base.

TABLE 15. ENVIRONMENTAL COMPARISON OF POTENITAL TAR SAND PRODUCTION AND PROCESSING METHODS

Operation or Process	Status of Tar Sand Technology	Major Potential Technical Disadvantages or Environmental Impacts	Major Potential Technical or Environmental Advantages
PRODUCTION			
(1) Surface Mining	One commercial operation in Canada; others planned or proposed. Small scale open-pit projects in U.S. No large-scale demonstration of technology in U.S.	Most potential for surface changes during mining. Least potential for complete restoration of surface to premining condition. Require removal and transportation of tar sands. Disadvantages include those of extraction (see below). Most potential for increasing availability of aqueous transportable materials. Generates most solid waste (mine waste plus spent sand). Greatest materials handling requirements (solid waste plus tar sand).	Basic surface mining technology applicable. High to highest bitumen recovery.
(2) Underground Mining	Applicability of available underground mining technology not yet investigated	Require removal and transportation of tar sands. Create potential for surface subsidence. Disadvantages include those of extraction (see below).	Can draw from available underground mining technology. Potential for underground disposal of spent sand. High bitumen recovery (longwall method of mining). Least potential (among mining methods) for surface changes during mining. Best potential (among mining methods) for minimizing permanent surface changes if no subsidence and spent sand returned to mine. Eliminates stripping operation and resultant solid wastes.

TABLE 15. (Continued)

Operation or Process	Status of Tar Sand Technology	Major Potential Technical Disadvantages or Environmental Impacts	Major Potential Technical or Environmental Advantages
(3) Longwall Stripping	Applicability to tar sands not yet investigated.	Require removal and transportation of tar sand. Disadvantages include those of extraction. If used after contour mining would probably increase potential for environmental impact.	Applicability of method for mining of coal under investigation. Total potential for environmental impact probably less than that of other methods of mining same amount of sands. If used after contour mining, could recover greater percentage of tar sand deposit.
(4) In Situ Production From Surface	No commercial production to date from tar sands. Pilot projects have been conducted but in situ technologies for commercially producing tar sands are not yet demonstrated.	Nonuniform nature of tar sand characteristics poses technical problems. Bitumen recovery expected to be less than that for surface mining. Availability of water unless coproduced water treated and reused (depending on location and method)	Basic technologies include those of producing heavy oil reservoirs. Produce tar sands that are too deep to be produced economically by mining methods. Eliminate generation of solid waste of mining and spent sand from extraction process. Some upgrading of tar sand bitumen could occur underground. Coproduced waters could be disposed of by subsurface treated and reused in water-short areas. Disturb much less surface area than surface mining. Eliminate potential sources of dust and noise in surface mining operation.
(5) In Situ Production Underground	Applicability to tar sands not yet investigated.	Disadvantages probably would be similar to those of surface in situ production.	U.S.S.R. reported to be producing heavy oil deposit by this method(20) Other advantages probably would be similar to those of surface in situ production.

TABLE 15. (Continued)

Operation or Process	Status of Tar Sand Technology	Major Potential Technical Disadvantages or Environmental Impacts	Major Potential Technical or Environmental Advantages
EXTRACTION OF BITUMEN FROM MINED TAR SAND	Wet Process: One commercial operation in Canada; others planned or proposed. Small scale or bench tests in U.S. Retorting: Applicability to tar sands generally unevaluated experimentally.	Wet Process: Generation and disposal of solid wastes (spent sand). Availability of water if process water not reused. Leached constituents in waste water effluents. Retorting: Availability of water for once-through cooling systems. High temperature could result in more contaminants in syncrude than wet processes.	Wet Process: Could result in less contaminants in syncrude than retorting. Retorting: Could be less potential for water pollution than in wet processes.

As indicated above, development of a tar sand industry using in situ methods of production poses the least potential for environmental impact. From the viewpoint of maximum utilization of a tar sands resource base, production of tar sands by surface mining would be preferred. In situ methods or possibly underground mining might be possible, however, in lieu of surface mining in environmentally sensitive areas where technical and economic factors permit a choice of production method.

SECTION VI

ENERGY PERSPECTIVE OF U.S. TAR SANDS

Factors restraining development of U.S. tar sands relate to or stem from:

- Need for exploration of the deposits to acquire data for evaluating their commercial attractiveness and for developing a proven production and processing technology
- Lack of proven production and processing technologies, particularly in situ technology, applicable to U.S. deposits
- Envisioned problems, project delays, or cancellations, because of possible or probable problems with environmental acceptability of a tar sands industry. Major percentage of deposits underlie or are in environs of national parks and monuments, pristine wilderness areas, and arid/semiarid mountainous terrain.
- Net energy to be gained (energy balance)
- Competitive position of tar sands vis-a-vis other energy sources (e.g., teritiary recovery of oil, shale oil, liquefaction and gasification of coal, and deep water offshore oil) for manpower, equipment manufacturing and construction resources, and available capital.
- U.S. tar sands, as now known, represent a comparatively small resource base.
- Economic incentives and risks, investment climate, product price, and governmental policies.

Given a resolution of restraints favorable for development of tar sands, a "ball park" perspective of U.S. tar sands is that they might potentially represent 7 to 10 billion barrels of syncrude, depending on how one speculates on the values and combinations of the production variables involved. Production variables include those shown in Table 16 as well as the percentage of tar sand reservoirs produced by each of the methods.

Ten billion barrels of syncrude from tar sands would be approximately 3-1/4 times the amount of natural domestic crude produced in 1975 and 6-3/4

TABLE 16. EFFECT OF PRODUCTION VARIABLES ON UTILIZATION OF TAR SAND RESOURCES

Production Method	Assumptions	% of In Place Bitumen Produced
Surface Mining	100% of Ore Recovered 90% Extraction Efficiency (a)	90
	90% of Ore Recovered 90% Extraction Efficiency	81
Underground Mining (b)		
Continuous or Conventional	55% of Ore Recovered 90% Extraction Efficiency	50
Longwall	80% of Ore Recovered 90% Extraction Efficiency	72
In Situ	50% Sweep Efficiency (c) 70% Displacement (d)	35
	75% Sweep Efficiency 70% Displacement	50
	90% Sweep Efficiency 70% Displacement	63

(a) Extraction efficiency: % of bitumen recovered from ore processed at extraction plant.

(b) Underground mining of tar sands seldom mentioned in literature. Ore recovery based on experience from underground mining of coal.

(c) Sweep efficiency: % of ore body's total volume from which bitumen is removed.

(d) Displacement: % of bitumen in affected volume driven to production wells.

times the amount of natural crude imported by the U.S. in 1975 (based on values in Monthly Energy Review, FEA, PB-242769-12, December, 1975. Even if all of the 30-billion barrel tar sand resource base were commercially producable, domestic tar sand deposits would not approach the 600-billion barrel(3) resource base of the oil shale deposits of the Green River Formation in western U.S. Consensus is that something in the neighborhood of 7 to 10 years would be required to attain large-scale production of U.S. tar sands, assuming a favorable resolution of the restraints listed previously.

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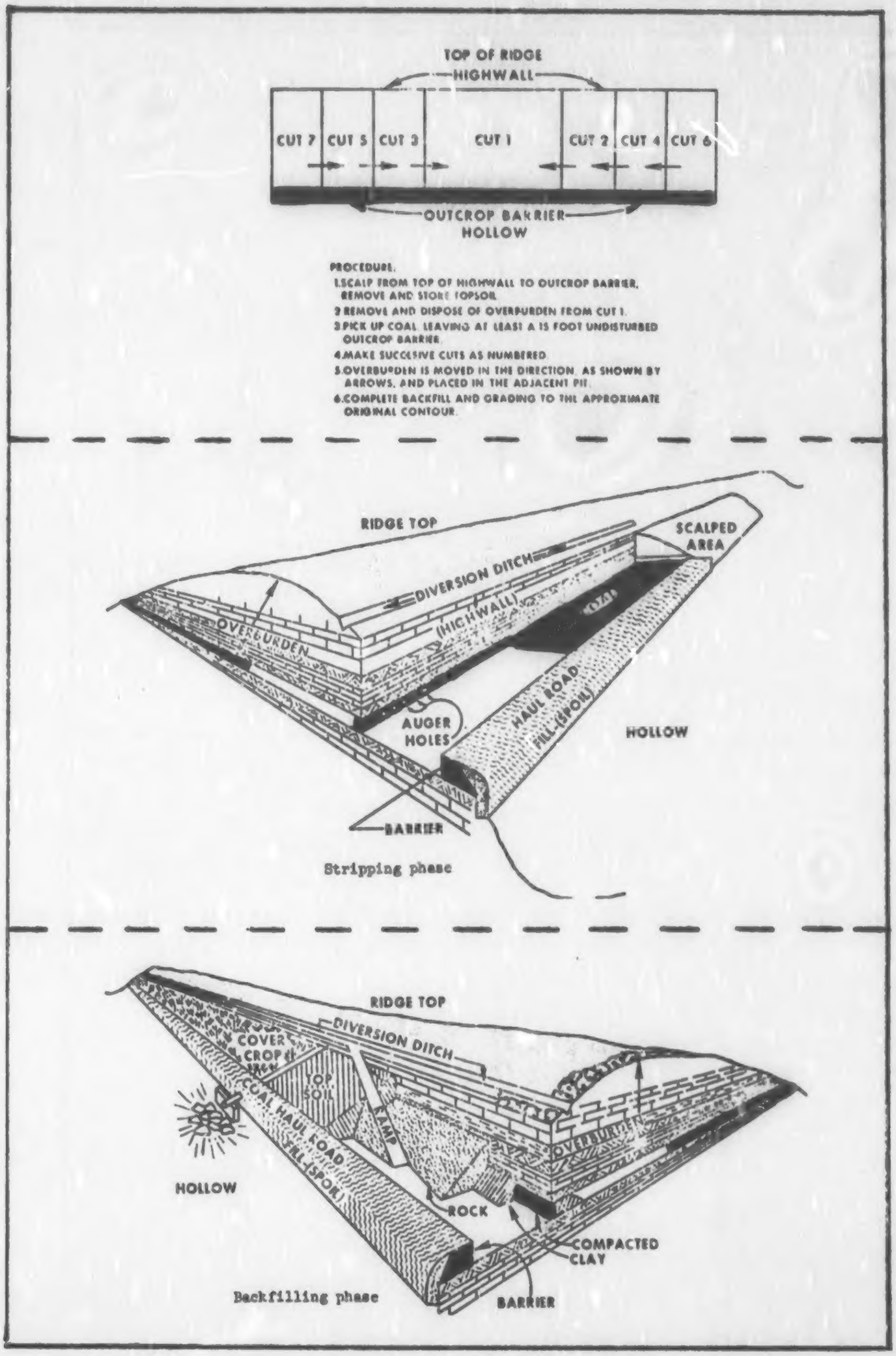
APPENDIX A

ILLUSTRATIONS OF MINING METHODS

(Figures A-1 to A-6 Reproduced/Modified from Reference 21. Figure A-7 Reproduced/Modified from Reference 23)


TOP OF RIDGE
HIGHWALL
CUT 7
CUT 5
CUT 3
CUT 1
CUT 2
CUT 4
CUT 6
OUTCROP BARRIER
HOLLOW
RIDGE TOP
SCALPED AREA
DIVERSION DITCH
(HIGHWALL)
OVERBURDEN
AUGER HOLES
HAUL ROAD
FILL (SPOIL)
HOLLOW
BARRIER
RIDGE TOP
DIVERSION DITCH
COVER CROP
TOP SOIL
RAMP
COAL HAUL ROAD
FILL (SPOIL)
HOLLOW
OVERBURDEN
ROCK
COMPACTED CLAY
BARRIER

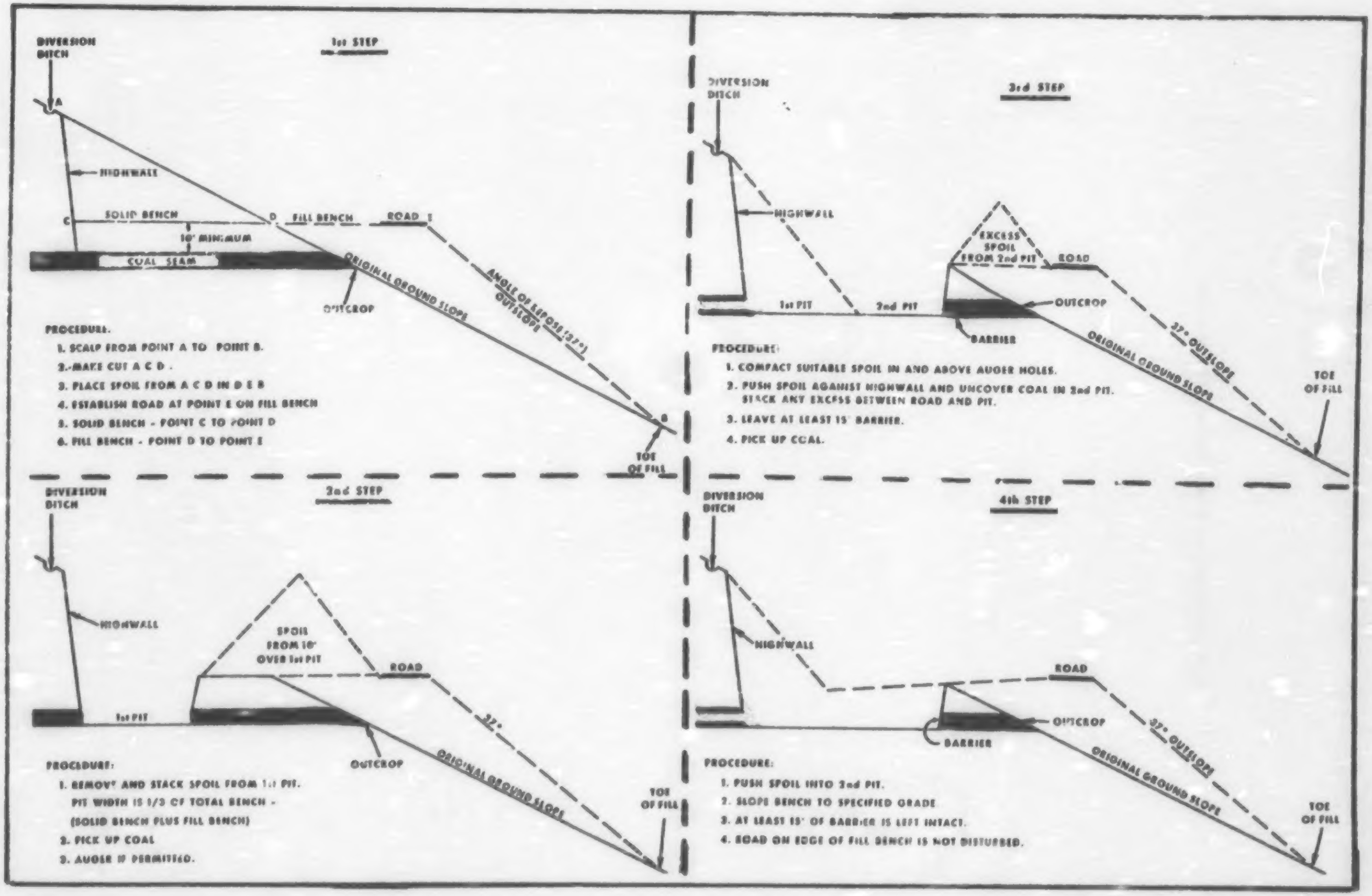
PROCEDURE.

1. SCALP FROM TOP OF HIGHWALL TO OUTCROP BARRIER, REMOVE AND STORE TOPSOIL.
2. REMOVE AND DISPOSE OF OVERBURDEN FROM CUT 1.
3. PICK UP COAL LEAVING AT LEAST A 15 FOOT UNDISTURBED OUTCROP BARRIER.
4. MAKE SUCCESIVE CUTS AS NUMBERED.
5. OVERBURDEN IS MOVED IN THE DIRECTION, AS SHOWN BY ARROWS, AND PLACED IN THE ADJACENT PIT.
6. COMPLETE BACKFILL AND GRADING TO THE APPROXIMATE ORIGINAL CONTOUR.

Stripping phase

Backfilling phase

FIGURE A-1. BLOCK CUT METHOD


1st STEP
DIVERSION DITCH
A
HIGHWALL
C
SOLID BENCH
D
FILL BENCH
ROAD
E
10' MINIMUM
COAL SEAM
OUTCROP
ORIGINAL GROUND SLOPE
ANGLE OF REPOSE (37°)
OUTSLOPE
B
TOE OF FILL
2nd STEP
DIVERSION DITCH
HIGHWALL
SPOIL FROM 10' OVER 1st PIT
ROAD
1st PIT
37°
OUTCROP
ORIGINAL GROUND SLOPE
TOE OF FILL
3rd STEP
DIVERSION DITCH
HIGHWALL
EXCESS SPOIL FROM 2nd PIT
ROAD
1st PIT
2nd PIT
OUTCROP
BARRIER
37° OUTSLOPE
ORIGINAL GROUND SLOPE
TOE OF FILL
4th STEP
DIVERSION DITCH
HIGHWALL
ROAD
OUTCROP
BARRIER
37° OUTSLOPE
ORIGINAL GROUND SLOPE
TOE OF FILL

PROCEDURE.

1. SCALP FROM POINT A TO POINT B.
2.-MAKE CUT A C D.
3. PLACE SPOIL FROM A C D IN D E B
4. ESTABLISH ROAD AT POINT E ON FILL BENCH
5. SOLID BENCH - POINT C TO POINT D
6. FILL BENCH - POINT D TO POINT E

PROCEDURE:

1. REMOVE AND STACK SPOIL FROM 1st PIT. PIT WIDTH IS 1/3 OF TOTAL BENCH - (SOLID BENCH PLUS FILL BENCH)
2. PICK UP COAL
3. AUGER IF PERMITTED.

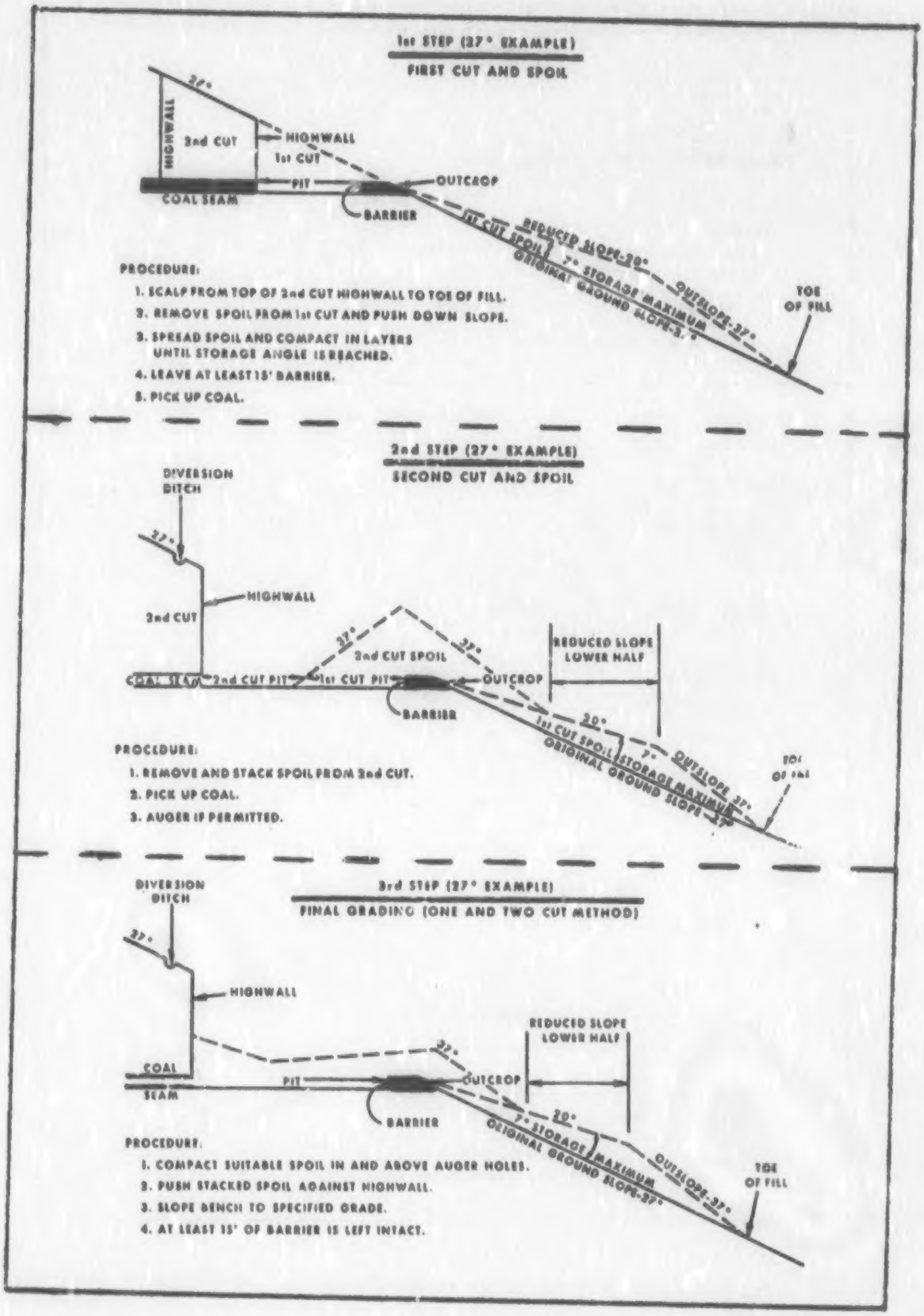
PROCEDURE:

1. COMPACT SUITABLE SPOIL IN AND ABOVE AUGER HOLES.
2. PUSH SPOIL AGAINST HIGHWALL AND UNCOVER COAL IN 2nd PIT. STACK ANY EXCESS BETWEEN ROAD AND PIT.
3. LEAVE AT LEAST 15' BARRIER.
4. PICK UP COAL.

PROCEDURE:

1. PUSH SPOIL INTO 2nd PIT.
2. SLOPE BENCH TO SPECIFIED GRADE.
3. AT LEAST 15' OF BARRIER IS LEFT INTACT.
4. ROAD ON EDGE OF FILL BENCH IS NOT DISTURBED.

FIGURE A-2. BOX-CUT METHOD (TWO-CUT)



1st STEP (27° EXAMPLE)

FIRST CUT AND SPOIL

27°
HIGHWALL
2nd CUT
HIGHWALL
1st CUT
PIT
OUTCROP
COAL SEAM
BARRIER
1st CUT SPOIL
REDUCED SLOPE-20°
7° STORAGE MAXIMUM
ORIGINAL GROUND SLOPE-27°
OUTSLOPE-27°
TOE OF FILL

PROCEDURE:

1. SCALP FROM TOP OF 2nd CUT HIGHWALL TO TOE OF FILL.
2. REMOVE SPOIL FROM 1st CUT AND PUSH DOWN SLOPE.
3. SPREAD SPOIL AND COMPACT IN LAYERS UNTIL STORAGE ANGLE IS REACHED.
4. LEAVE AT LEAST 15' BARRIER.
5. PICK UP COAL.

2nd STEP (27° EXAMPLE)

SECOND CUT AND SPOIL

DIVERSION DITCH
27°
HIGHWALL
2nd CUT
27°
27°
2nd CUT SPOIL
REDUCED SLOPE LOWER HALF
COAL SEAM
2nd CUT PIT
1st CUT PIT
OUTCROP
BARRIER
20°
1st CUT SPOIL
7°
STORAGE MAXIMUM
ORIGINAL GROUND SLOPE-27°
OUTSLOPE-27°
TOE OF FILL

PROCEDURE:

1. REMOVE AND STACK SPOIL FROM 2nd CUT.
2. PICK UP COAL.
3. AUGER IF PERMITTED.

3rd STEP (27° EXAMPLE)

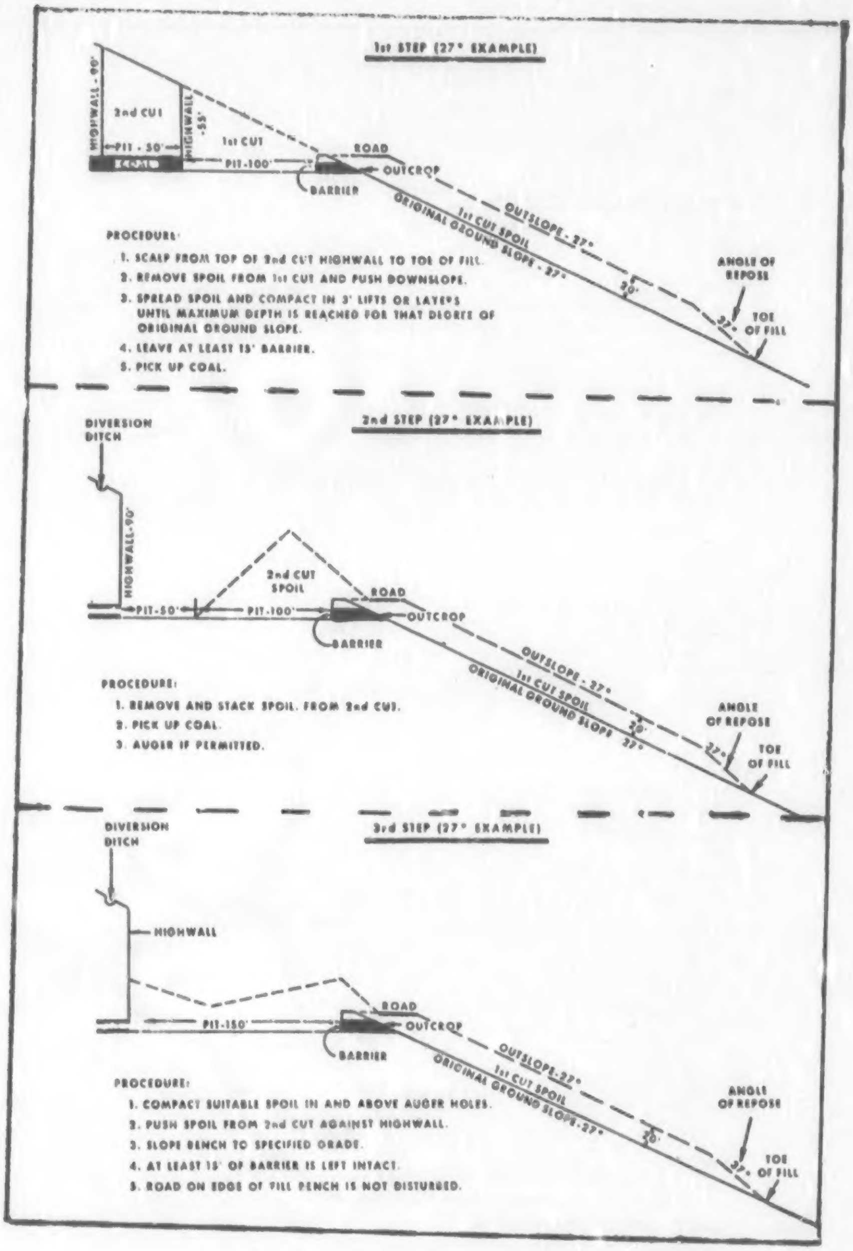
FINAL GRADING (ONE AND TWO CUT METHOD)

DIVERSION DITCH
27°
HIGHWALL
27°
REDUCED SLOPE LOWER HALF
COAL SEAM
PIT
OUTCROP
BARRIER
20°
7° STORAGE
MAXIMUM
ORIGINAL GROUND SLOPE-27°
OUTSLOPE-27°
TOE OF FILL

PROCEDURE:

1. COMPACT SUITABLE SPOIL IN AND ABOVE AUGER HOLES.
2. PUSH STACKED SPOIL AGAINST HIGHWALL.
3. SLOPE BENCH TO SPECIFIED GRADE.
4. AT LEAST 15' OF BARRIER IS LEFT INTACT.

FIGURE A-3. SLOPE REDUCTION: ONE AND TWO-CUT METHOD


HIGHWALL - 90'
2nd CUT
HIGHWALL - 55'
1st CUT
PIT - 50'
PIT - 100'
ROAD
OUTCROP
BARRIER
OUTSLOPE - 27°
1st CUT SPOIL
ORIGINAL GROUND SLOPE - 27°
20'
ANGLE OF REPOSE
37°
TOE OF FILL
DIVERSION DITCH
HIGHWALL - 90'
2nd CUT SPOIL
PIT - 50'
PIT - 100'
ROAD
OUTCROP
BARRIER
OUTSLOPE - 27°
1st CUT SPOIL
ORIGINAL GROUND SLOPE 27°
20'
ANGLE OF REPOSE
37°
TOE OF FILL
DIVERSION DITCH
HIGHWALL
PIT - 150'
ROAD
OUTCROP
BARRIER
OUTSLOPE - 27°
1st CUT SPOIL
ORIGINAL GROUND SLOPE - 27°
20'
ANGLE OF REPOSE
37°
TOE OF FILL

1st STEP (27° EXAMPLE)

PROCEDURE:

1. SCALP FROM TOP OF 2nd CUT HIGHWALL TO TOE OF FILL.
2. REMOVE SPOIL FROM 1st CUT AND PUSH DOWNSLOPE.
3. SPREAD SPOIL AND COMPACT IN 3' LIFTS OR LAYERS UNTIL MAXIMUM DEPTH IS REACHED FOR THAT DEGREE OF ORIGINAL GROUND SLOPE.
4. LEAVE AT LEAST 15' BARRIER.
5. PICK UP COAL.

2nd STEP (27° EXAMPLE)

PROCEDURE:

1. REMOVE AND STACK SPOIL FROM 2nd CUT.
2. PICK UP COAL.
3. AUGER IF PERMITTED.

3rd STEP (27° EXAMPLE)

PROCEDURE:

1. COMPACT SUITABLE SPOIL IN AND ABOVE AUGER HOLES.
2. PUSH SPOIL FROM 2nd CUT AGAINST HIGHWALL.
3. SLOPE BENCH TO SPECIFIED GRADE.
4. AT LEAST 15' OF BARRIER IS LEFT INTACT.
5. ROAD ON EDGE OF FILL BENCH IS NOT DISTURBED.

FIGURE A-4. PARALLEL FILL METHOD, MODIFIED SLOPE REDUCTION

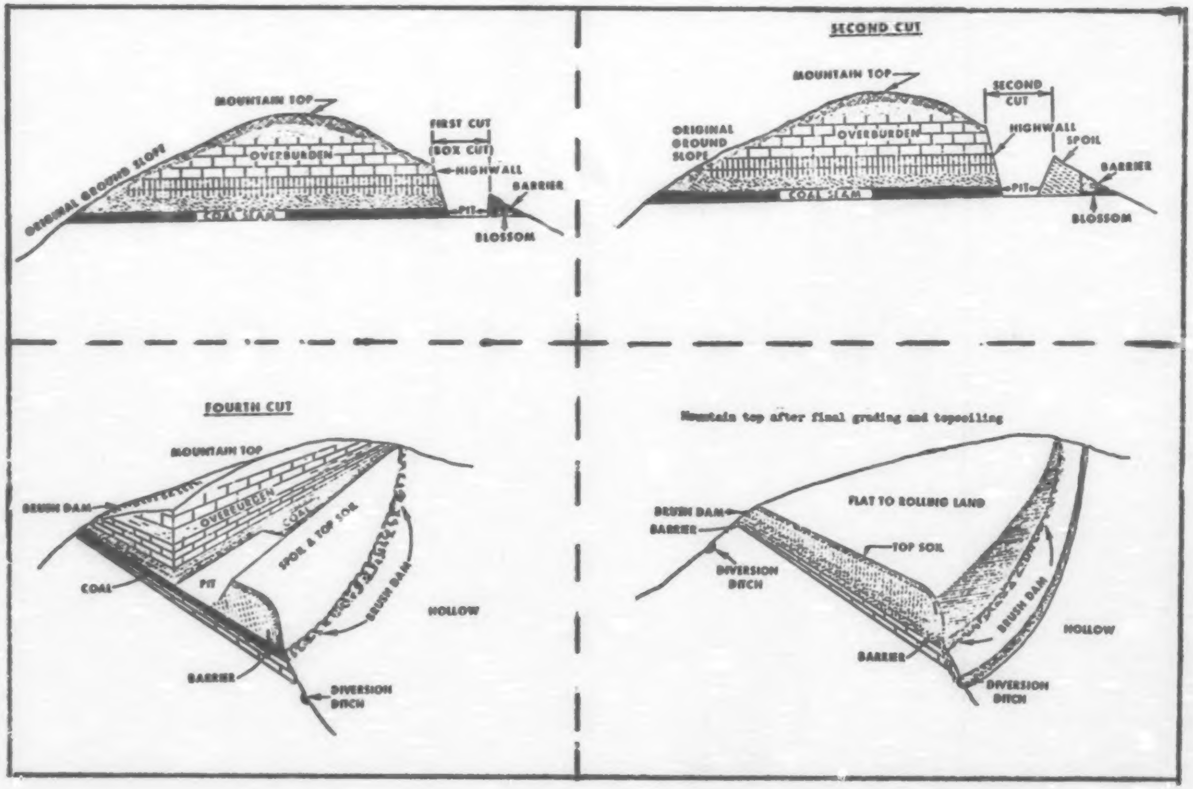

MOUNTAIN TOP
OVERBURDEN
ORIGINAL GROUND SLOPE
COAL SEAM
FIRST CUT
(BOX CUT)
HIGHWALL
PIT
BARRIER
BLOSSOM
SECOND CUT
MOUNTAIN TOP
ORIGINAL GROUND SLOPE
OVERBURDEN
COAL SEAM
SECOND CUT
HIGHWALL
SPOIL
PIT
BARRIER
BLOSSOM
FOURTH CUT
MOUNTAIN TOP
BRUSH DAM
OVERBURDEN
COAL
COAL
PIT
SPOIL & TOP SOIL
BRUSH DAM
HOLLOW
BARRIER
DIVERSION DITCH
Mountain top after final grading and topsoiling
BRUSH DAM
BARRIER
DIVERSION DITCH
FLAT TO ROLLING LAND
TOP SOIL
BRUSH DAM
HOLLOW
BARRIER
DIVERSION DITCH

FIGURE A-5. MOUNTAIN TOP REMOVAL METHOD

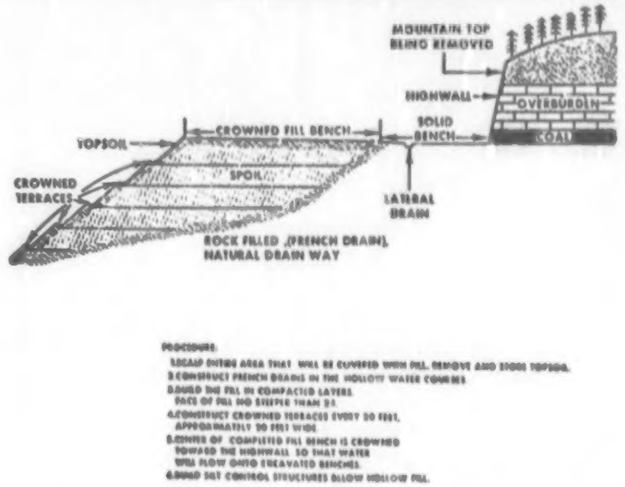
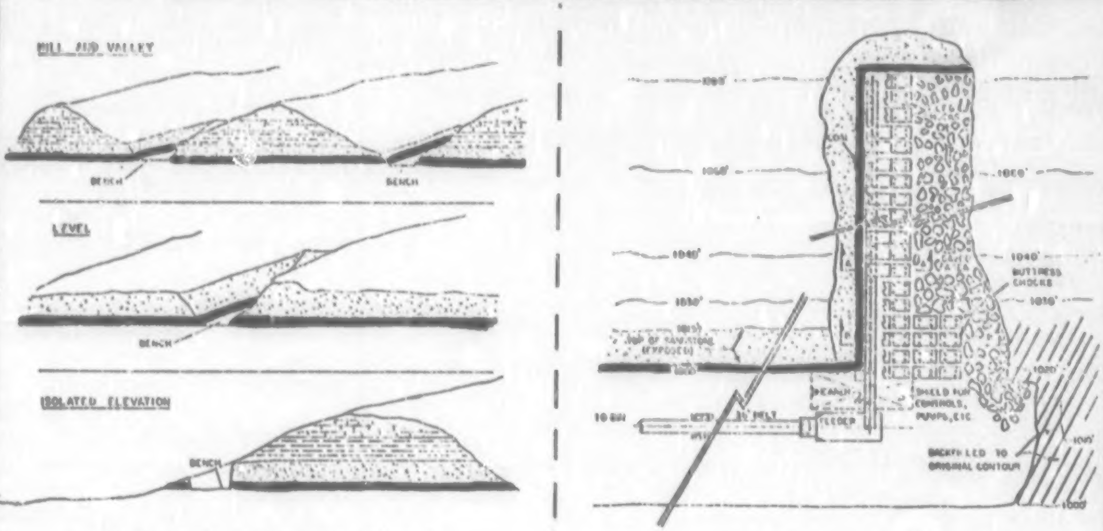
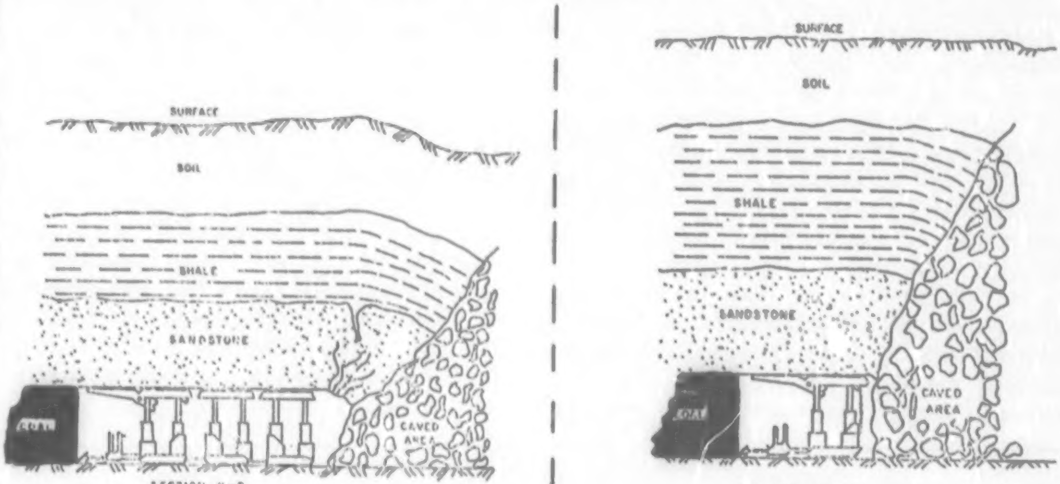

MOUNTAIN TOP
BEING REMOVED
HIGHWALL
OVERBURDEN
COAL
SOLID
BENCH
CROWNED FILL BENCH
TOPSOIL
SPOIL
CROWNED
TERRACES
LATERAL
DRAIN
ROCK FILLED ,(FRENCH DRAIN),
NATURAL DRAIN WAY
PROCEDURE:
1.CLEAR ENTIRE AREA THAT WILL BE COVERED WITH FILL, REMOVE AND STORE TOPSOIL.
2.CONSTRUCT FRENCH DRAINS IN THE HOLLOW WATER COURSES
3.BUILD THE FILL IN COMPACTED LAYERS.
FACE OF FILL NO STEEPER THAN 2:1
4.CONSTRUCT CROWNED TERRACES EVERY 50 FEET,
APPROXIMATELY 20 FEET WIDE.
5.CENTER OF COMPLETED FILL BENCH IS CROWNED
TOWARD THE HIGHWALL SO THAT WATER
WILL FLOW ONTO EXCAVATED BENCHES.
6.BUILD SILT CONTROL STRUCTURES BELOW HOLLOW FILL.

FIGURE A-6. HEAD-OF-HOLLOW FILL


HILL AND VALLEY
BENCH
BENCH
LEVEL
BENCH
ISOLATED ELEVATION
BENCH
1060'
1050'
1050'
1040'
1040'
BUTTRESS CHOCKS
1030'
1030'
TOP OF SANDSTONE (EXPOSED)
BENCH
SHIELD FOR CONTROLS, PUMPS, ETC
FEEDER
BELT
TO BIN
1020'
1010'
BACKFILLED TO ORIGINAL CONTOUR
1000'

VARIOUS TYPES OF TERRAIN APPLICABLE TO LONGWALL STRIPPING SYSTEM

PLAN VIEW OF LONGWALL STRIPPING SYSTEM


SURFACE
SOIL
SHALE
SANDSTONE
COAL
CAVED AREA
SURFACE
SOIL
SHALE
SANDSTONE
COAL
CAVED AREA

SECTION B-B

CROSS-SECTION VIEW OF LONGWALL STRIPPING SYSTEM ALONG HIGHWALL.

SECTION A-A

TYPICAL CROSS-SECTION VIEW OF LONGWALL STRIPPING SYSTEM

FIGURE A-7. LONGWALL STRIPPING